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VOLUME 1

SUBMISSION

APPENDICES

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VOLUME 1

SUBMISSION

APPENDICES

I J M

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THE GENERAL FUNCTIONS AND POLICIES

OF THE

OIL AND GAS CONSERVATION BOARD

PROVINCE OF ALBERTA

Oil and Gas Conservation Board,
603 - 6th Avenue S.W., Calgary, Alberta.

I. N. McKinnon, Chairman
D. P. Goodall, P. Eng., Deputy Chairman
G. W. Govier, P. Eng., Member

THE GENERAL FUNCTIONS AND POLICIES
OF THE
OIL AND GAS CONSERVATION BOARD
PROVINCE OF ALBERTA

A Submission to the Royal Commission
on Energy under the Chairmanship of Henry Borden Esq.
February 3, 1958

PREFACE

This submission is designed to acquaint members of the Commission with the general functions and policies of the Oil and Gas Conservation Board, Province of Alberta. The Board functions relate primarily to the production side of the oil and gas industry, to the effective utilization of gas, and to the removal of gas from the Province. The Board is not concerned with the refining of oil and deals only incidentally with the transportation and removal from the Province of oil.

Statements of Oil and Gas Reserves and Trends in Growth of Reserves are included. Also, for the convenience of the Commission, the Geology of Alberta and the Nature of Oil and Gas are discussed briefly.

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INTRODUCTION

The first Oil and Gas Conservation Act was passed in Alberta in 1938 and provided for the setting up of a Conservation Board. The present Oil and Gas Conservation Board functions under, and is responsible for the administration of, the Oil and Gas Conservation Act[1]. The basic conservation concepts are set forth in section 4 of the Act which reads:

"4. The intent and purpose of this Act are

(a) to effect the conservation of the oil and gas resources of the Province,

(b) to prevent the waste[2] of the oil and gas resources of the Province,

(c) to secure the observance of safe and efficient practices in the locating, spacing, drilling, equipping, completing, reworking, testing, operating and abandonment of wells and in all operations for the production of oil and gas, and

(d) to afford to each owner the opportunity of obtaining his just and equitable share of the production of any pool.".

The Act applies to all wells in the Province whether they be on Crown or freehold lands.

(1) Statutes of Alberta, 1957, c.63; Appendix A.

(2) "waste" and "wasteful operations" are defined in section 2 of the Act.

5 years

The Board is constituted under the Act as a body politic and corporate, and consists of three members who are appointed for a term of five years and thereafter during the pleasure of the Lieutenant Governor in Council. Members of the Board are prohibited from holding any interest whatsoever in any oil or gas property or in any business connected with the oil and gas industry.

The Board is given complete authority in the matter of appointing staff and may retain the services of any technical experts in an advisory capacity. The head office of the Board is in Calgary and there are a northern district office at Edmonton and nine regional offices located at Black Diamond, Devon, Medicine Hat, Redwater, Camrose, Stettler, Drayton Valley, Lloydminster and Red Deer. The present staff consists of some fifty-eight engineers, geologists, statisticians, and other professional persons and some one hundred and thirty-five non-professional. This includes the field staff that numbers some fifty and consists about half of engineers and half of technicians and clerks. The Board is financed by Government and by industry and freehold owners on an approximately fifty-fifty basis.

The powers of the Board and the scope of its conservation responsibilities are defined in the Oil and Gas Conservation Act. The Drilling and Production Regulations(3) established by order of the Lieutenant Governor in Council and the General Regulations(4) established by Board order, each under the authority

(3) Appendix A2
(4) Appendix A3

of the Act, detail the ground rules concerning the spacing, drilling and operation of oil and gas wells and the measurement of oil and gas.

Related to its conservation functions are the responsibilities of the Board concerning the removal of gas from the Province. The policy of the Province and the duties of the Board in implementing it are defined in the Gas Resources Preservation Act, 1956[5]. These are fully treated under a later heading.

The Acts and regulations which the Board administers have been amended and replaced from time to time as a result of knowledge gained. Alberta has had to pioneer oil and gas legislation in Canada but was fortunate in being able to make use of the vast experience gained over a long period of years in the United States. The development of conservation under such legislation is portrayed in An Historical Sketch of Oil and Gas Conservation in Alberta[6].

Valuable assistance has been received from the oil and gas industry itself in drafting new legislation and regulations. The task of the Board has been made a lot easier by the splendid support it has received from the industry in its efforts to promote efficient operating practices and procedures and to regulate production in the interests of securing the optimum recovery of our oil and gas reserves.

(5) Statutes of Alberta, 1956, c.19; Appendix B.
(6) Appendix C.

CHAPTER 11

THE NATURE OF OIL AND GAS

Crude oil is a liquid mixture of paraffinic and other hydrocarbons spanning a wide range of molecular weights and containing varying amounts of sulphur, nitrogen and other elements. It ranges in specific gravity (relative to water) from about 0.7 to nearly 1 (API gravity from 50 to nearly 10) and varies widely in volatility. Natural gas is a gaseous mixture of normal paraffinic hydrocarbons, mainly methane, which often is contaminated with water vapor, nitrogen, carbon dioxide and hydrogen sulphide.

American Petroleum Institute

The nature of the underground occurrence of oil and gas and its effect upon conservation were discussed in a general paper presented before the Canadian Institute of Mining and Metallurgy in 1950(7). The following discussion is abstracted from this paper. Although the oil and gas concentrations underground are referred to as pools, it should be understood that the oil and gas do not occur in underground lakes but in the pore spaces of porous permeable rock. While there is not even yet a clear understanding of the origin of oil and gas in the earth, underground concentrations of these fluids are found trapped in porous rocks by impermeable formation. The physical nature of the reservoir rock may vary over wide limits and from the finest grained sands to

(7) Appendix D

cavernous limestones, of which latter the Leduc D-3 reservoir rock is typical. The pore or non-rock space may vary from less than 5 per cent to over 25 per cent. Reservoir rocks may vary over even greater limits in respect to their ability to permit the migration or movement of oil or gas. Permeability, or ease with which flow is permitted, is analagous to electrical conductivity - the ease with which electrical current can flow. Permeability usually is measured in millidarcies and the permeability of oil and gas reservoir rocks is found generally to vary from well under 50 to over 1,000 millidarcies.

Connate Water

While most underground rocks exhibiting porosity and permeability are filled with salt water, an oil or gas reservoir contains oil or gas, as well as some water, in its pore spaces. The water which fills part of the void spaces is termed "connate" or "interstitial" water. It is believed to be water which was not displaced by the petroleum at the time of its accumulation and entrapment in the originally water saturated reservoir. The connate water content may range from 5 per cent to 40 per cent or more of the void space and is important, not only because it represents a part of the void space which does not contain oil or gas, but also because of the role it plays during the productive life of the reservoir.

Natural Gas

Natural gas as produced from a well may be divided into two separate categories:

1. Dry Gas

The term "dry gas" refers specifically to gas which, composed mainly of the low molecular weight gases, methane and ethane, has no economically recoverable liquid hydrocarbons (propane, butane, and pentanes plus) and is, usually, not associated in the reservoir with commercial quantities of crude oil. The specific gravity of dry gas, compared with air, varies from 0.55 to 0.70.

2. Wet Gas

Wet gas is defined as natural gas which contains an economically recoverable quantity of liquid hydrocarbons. The degree of liquid saturation varies greatly, from an almost dry gas exemplified by the Joarcam Viking gas cap to the very wet gas of the Windfall D-3 Reefal pool. Wet gas may further be classified as:

(1) Gas cap gas - found in the interstices of rock directly overlying crude oil accumulations, the gas in intimate contact with either a commercial or non-commercial deposit of crude oil.

(2) Solution gas - dissolved in the crude oil during its formation and accumulation and unavoidably produced coincidentally with it.

Gas cap gas and solution gas are often referred to as "associated gases".

(3) Gas condensate gas - a wet gaseous phase produced from gas condensate reservoirs of the Jumping Pound and Pincher Creek type of Mississippian accumulation.

Crude Oils

Crude oil accumulates as an "undersaturated" or "saturated" oil, both terms referring to the relative amount of gas dissolved in the oil. For those crudes in which the amount of gas dissolved is less than that physically possible for the reservoir's pressure and temperature, the crude is called undersaturated. The degree of undersaturation for crude oils varies from slightly below the maximum amount of gas that could be dissolved in the oil to a large amount of undersaturation. Alternately, a saturated crude has the maximum amount of gas in solution. Saturated crude oils generally have gas caps of various sizes associated with the oil, ranging from a fraction to possibly 100 times the reservoir rock volume of the oil zone. An example of an undersaturated crude is that found in the Pembina Cardium reservoir, and of a saturated crude, that of the Leduc-Woodbend D-3 productive zone.

Condensate

In deep reservoirs, particularly in the foothills and "disturbed belt" region of Alberta, a hydrocarbon mixture which really is neither gas nor liquid is frequently found.

These mixtures are ones which, in the reservoir, exist as a single fluid phase at reservoir pressure and temperature, yet, on being produced through surface separation devices form a "wet gas" and an oily liquid or "condensate". The condensate is a white to slightly colored high quality oil of 45° to 70° API, not unlike a mixture of gasoline and very light machine oil.

Contaminants

Natural gases, crude oils, and condensates contain carbon dioxide, nitrogen, hydrogen sulphide and various other contaminants. The term "sour" is applied to those hydrocarbons which possess hydrogen sulphide - without it, the hydrocarbons are "sweet". Most Viking reservoirs in Alberta are "sweet", most Mississippian and Devonian pools are "sour".

Bottom Water

Quite often the hydrocarbon fluids are underlaid in the reservoir by water, that is, the pore spaces below the accumulation of oil and gas are completely filled with water. In the event of the occurrence of a saturated crude with an associated gas cap, the fluids arrange themselves, by gravitational segregation over geological time, so that the gas overlies the oil with a transition "gas-oil" zone between them, and the oil overlies the "bottom water" with a transition "oil-water" zone between it and the water.

Reservoir Drive

Oil of itself has little inherent energy to cause it to flow either to the bore of the hole man may drill into it or up the pipe man may lead from the surface to the reservoir. True, oil under pressure has a certain amount of compressive energy which aids in its expulsion from the reservoir but this is seldom sufficient to cause the flow of more than a very small fraction of the oil in the reservoir. The movement of oil from surrounding parts of the reservoir to the well bore and (in the case of a "flowing" well) up the tubing, is caused mainly by a displacement process involving the expansion either of underlying water or of gas. There are three major mechanisms by which oil may be displaced and caused to move to the well bore. These "reservoir drives" as they are called, are the water drive, the solution gas drive, and the gas cap drive.

Water Drive

In the event of a reservoir being underlaid by a sufficiently large body of water, the oil or gas may be displaced by the upward expansion of the underlying water. This, the so-called water drive, is ordinarily the most efficient displacement process. A water drive may be developed when, because of pressure release at the well bore, a vast body of compressed water expands and moves toward the region of pressure release, pushing oil in front of it. The water drive mechanism is aided by gravitational segregation

and is efficient only when the rate of advance of the water front is extremely slow. Since the advance of the water-oil or water-gas interface is caused by the pressure release attending production of oil or gas the rate of advance of the interface generally is proportional to the rate of production of oil or gas. It, therefore, follows that the water drive mechanism can only be efficient when the rate of production, which controls the rate of advance of the water front, is maintained at an efficient low value. Experience in the operation of water drive oil fields, coupled with laboratory tests and theory, tells us that under ideal conditions recoveries as high as some 80 per cent of the oil in the reservoir might be expected.

Solution Gas Drive

Regardless of the existence or otherwise of a large body of underlying water, if the crude oil contains gas in solution - and particularly if the oil is saturated with gas - a solution gas drive may develop. This type of driving action occurs whenever the reservoir pressure is lowered to the point where gas starts to break out of solution from the oil. In the case of saturated crudes even a slight lowering in pressure causes gas evolution, while in the case of under-saturated crudes a substantial pressure decline may be required. In the solution gas drive the displacement of the oil results from the expansion and flow of gas evolved from solution in the oil. This is analagous to the displacement

of soda-water by the evolution and expansion of dissolved carbon dioxide gas when the cap of a bottle (and the confining pressure) is removed.

The solution gas drive is not an efficient displacement process. While the oil recovery under this type of drive varies considerably with the characteristics of the reservoir fluids and the reservoir rock, recoveries of the order of 10 per cent to 25 per cent of the oil in the ground are all that may be expected.

Gas Cap Drive

The third type of displacement process, the gas cap drive, is one generally considered as intermediate in efficiency between the solution gas and the water drive. Here the displacement is accomplished with the aid of the downward, piston-like expansion of the overlying gas cap. This expansion occurs with production from the field and as the reservoir pressure declines. The gas cap mechanism, like the water drive, is a rate-sensitive process and high efficiencies result only when the rate of expansion of the gas cap and the downward movement of the gas-oil interface is kept low. Most important, however, is the preservation of the gas cap which provides the driving energy. This means the prohibition of production of gas cap gas until after the recoverable oil has been produced.

CHAPTER III

GEOLOGY OF ALBERTA

General Description

It is estimated that 96 per cent of Alberta is underlaid by deposits of sedimentary rock. The sediments cover a complex of igneous basement rock and thicken from their outcrop areas in northeastern Alberta to thicknesses exceeding 14,000 feet along the western edge of the Alberta plains and to even greater thicknesses in the foothills where thrust faulting may cause the cyclic repetition of formations. The manner in which the total thickness of sediments increases is illustrated in Figure III-1.

Geologists have classified the sedimentary deposits of Alberta into groups, formations and members, the most wide-spread being the group and the most restricted being the member. A group contains two or more formations, each of which may embody two or more less extensive members having some geological character in common. The names and relative positions of these geological units are illustrated in diagrammatic form by Figure III-2, entitled "Table of Formations - Alberta".

Nearly all formations thin or become non-existent in an eastward direction within the Province. This is caused by the fact that certain formations were deposited to greater thicknesses in the western part of Alberta and that some formations were truncated by erosional forces in an eastward direction at various times during the geological history of the Province. The cross-section, Figure III-3, illustrates the effect of truncation.

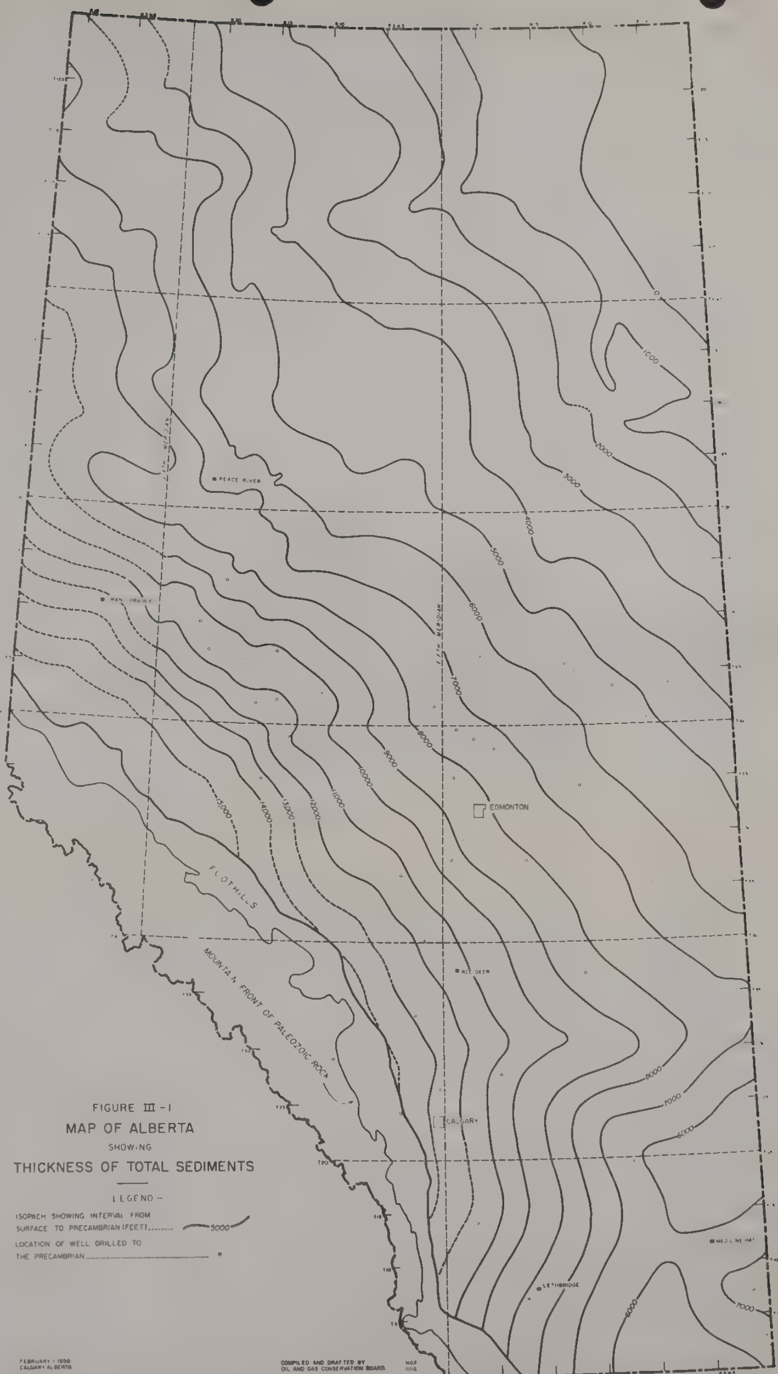
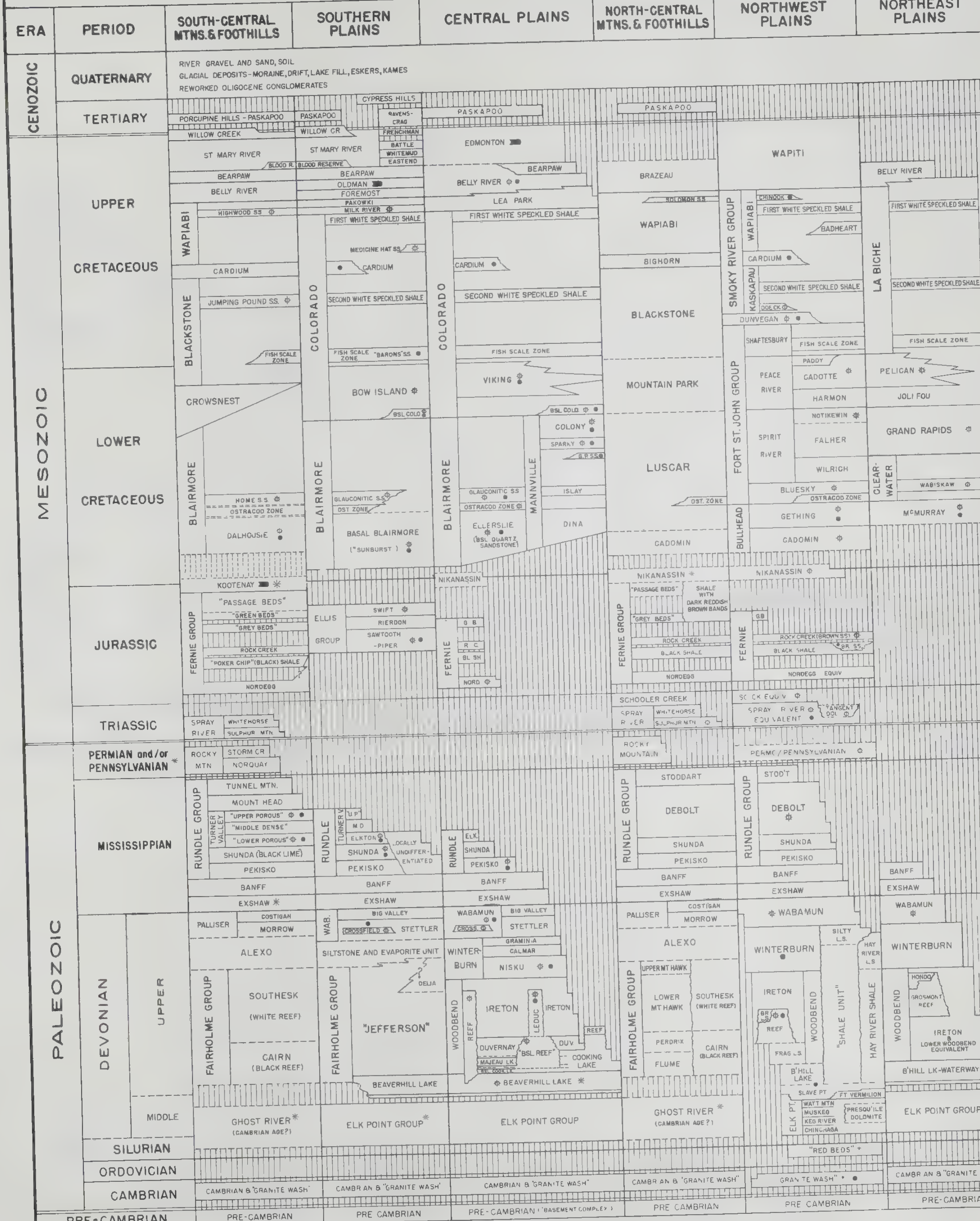


FIGURE III - I
MAP OF ALBERTA
SHOWING
THICKNESS OF TOTAL SEDIMENTS

TABLE OF FORMATIONS—ALBERTA



THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD

CALGARY, ALBERTA

15 JAN., 1957

FIGURE III-2

— LEGEND —

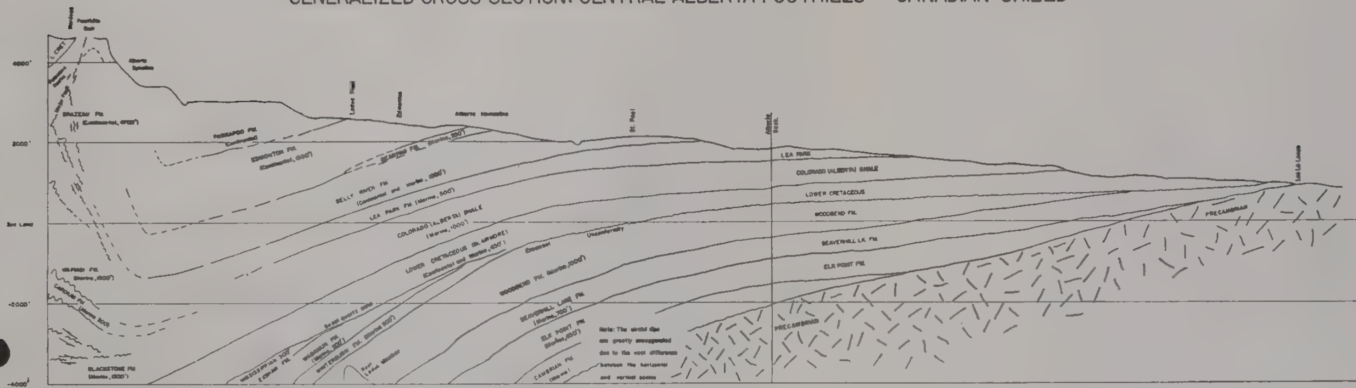
GAS .... ✲
OIL .... ●
COAL .... ▬
CORRELATION UNCERTAIN .... — — —
AGE NOT CONCLUSIVELY ESTABLISHED .... *
FACIES TRANSITION ...... \ or ⚡

— NOTE —

No official Board endorsement is intended for the nomenclature employed by this chart
Unit durations, thicknesses and erosional effects have not been drafted to a uniform scale
Northward, northeastward or eastward variations are depicted from left to right within each column
Pre-Cretaceous nomenclature and correlations in part after H Frebold (Can. O & G Indus., Feb '55), H B Peach (A A P G proposed nomenclature, June '56 Bull), J Law (A A P G Bull Oct '55) and H R Belyea, D G McLaren (A S P G Guide Book, '56)

FIGURE III — 3

GENERALIZED CROSS SECTION: CENTRAL ALBERTA FOOTHILLS — CANADIAN SHIELD



OIL AND GAS CONSERVATION BOARD
CALGARY, ALTA.

Beneath the plains of Alberta, covering an area of about 220,000 square miles, the formations dip gently in a southwestward direction except in the southeastern part of the Province where a positive geological feature accounts for regional dips in other directions. As a result of regional dip, the drilling depths required to evaluate a specific formation increase in a westward direction.

The rate of regional dip increases from only a few feet per mile in northeastern Alberta to nearly 100 feet per mile adjacent to the foothills. Localized structural anomalies may distort, over limited areas, the pattern of regional dip.

The narrow foothills and mountain belts, shown in Figure III-1, together occupy an area of approximately 25,000 square miles. They are underlaid by formations that have been folded and faulted by extreme compressive forces. This has resulted in a complexity of structural configurations.

Geological and Geographical Distribution of Known Oil and Gas Reserves

A number of formations underlying Alberta contain reserves of oil and gas. The reserves have accumulated in economic quantities where suitable reservoir rock and geological traps occur. The names and position of these productive formations are indicated in Figure III-2.

To date, approximately 27 per cent of the recoverable oil reserves and 41 per cent of the disposable gas reserves of Alberta have been discovered within the conglomerate and sandstone reservoirs contained by formations of Cretaceous age.

The remaining reserves have been found nearly entirely in the limestone and dolomite reservoirs of the underlying formations of Mississippian and Devonian age.

The relative significance of the major productive formations from the standpoint of discovered reserves is illustrated by Figures III-4 and III-5. These charts indicate that the majority of the recoverable oil reserves have been found in the Cardium and Leduc (D-3) formations and that the preponderance of disposable gas reserves have been discovered in the Rundle group and the Leduc formation.

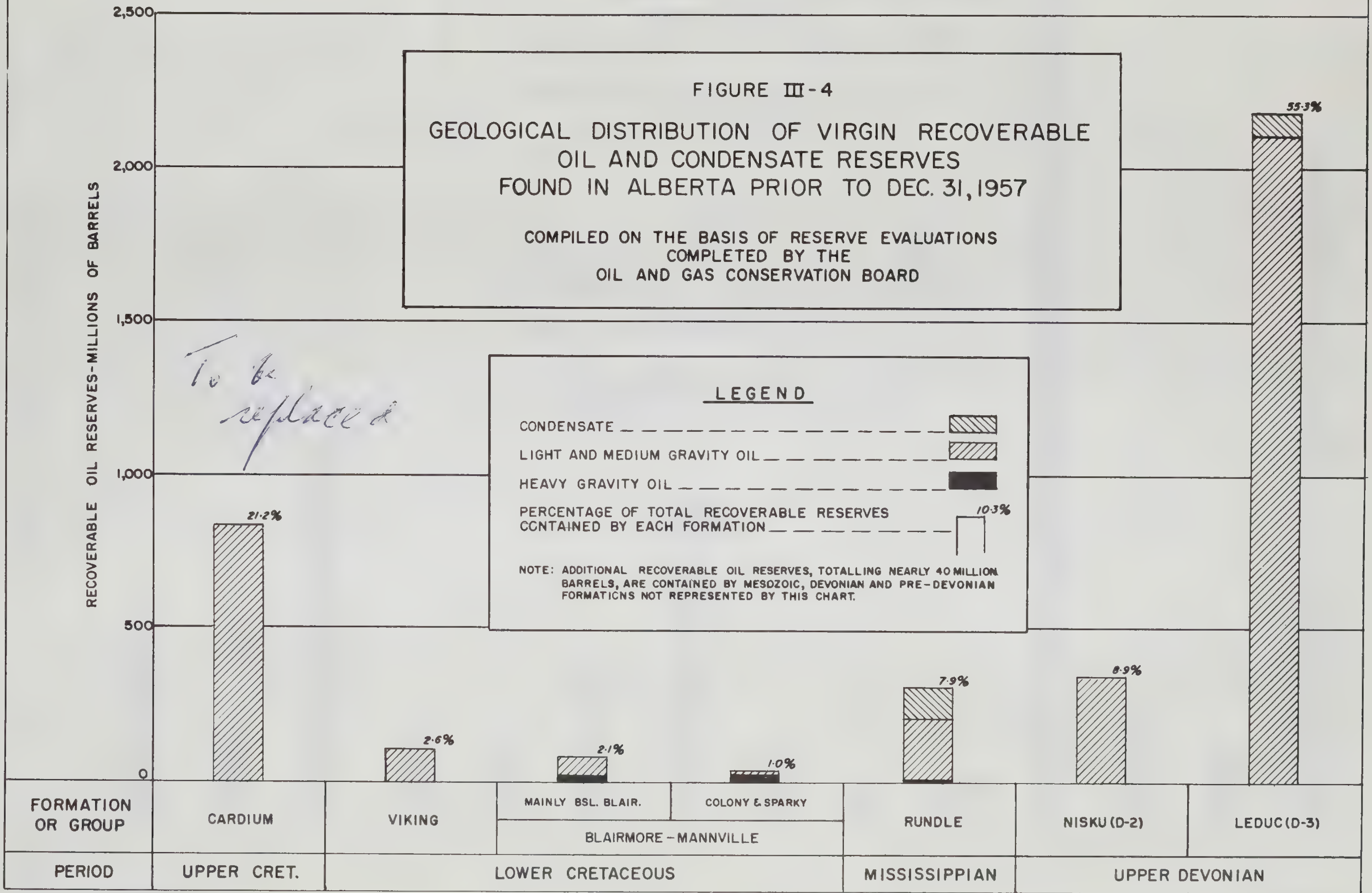
The geographical distribution of the known oil and gas reserves within the main producing formations of the Province is illustrated by Figures III-6 to III-9, inclusive. It is evident that the boundaries outlining the reserve areas may approximate either the truncated edges of the productive formation, the areal extremity of suitable trap development within the formation, or the limits of the successfully explored portion of a formation that is potentially productive over a wider area.

It is expected that future exploration will result in the discovery of additional large reserves both within and outside of the presently-delineated general reserve areas. Recent important gas discoveries in certain Mississippian and Devonian formations of the foothills and eastern mountains and oil discoveries in other Devonian formations underlying a part of northwestern Alberta are highly significant as they reveal the potentiality of formations and regions that, until recently, were not considered as highly prospective.

FIGURE III-4

GEOLOGICAL DISTRIBUTION OF VIRGIN RECOVERABLE OIL AND CONDENSATE RESERVES FOUND IN ALBERTA PRIOR TO DEC. 31, 1957

COMPILED ON THE BASIS OF RESERVE EVALUATIONS COMPLETED BY THE OIL AND GAS CONSERVATION BOARD



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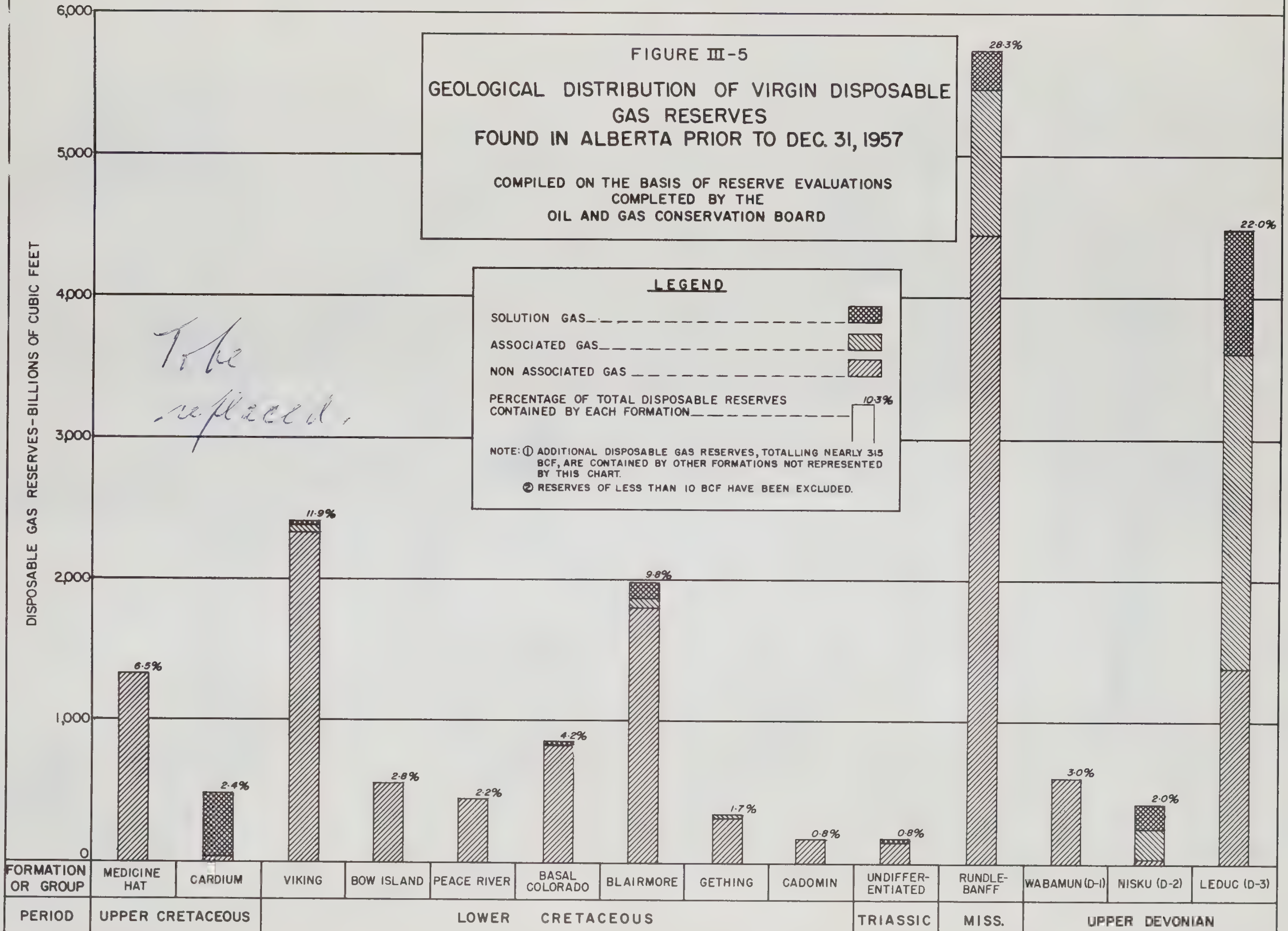

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CALGARY, ALBERTA

FEBRUARY 1, 1958

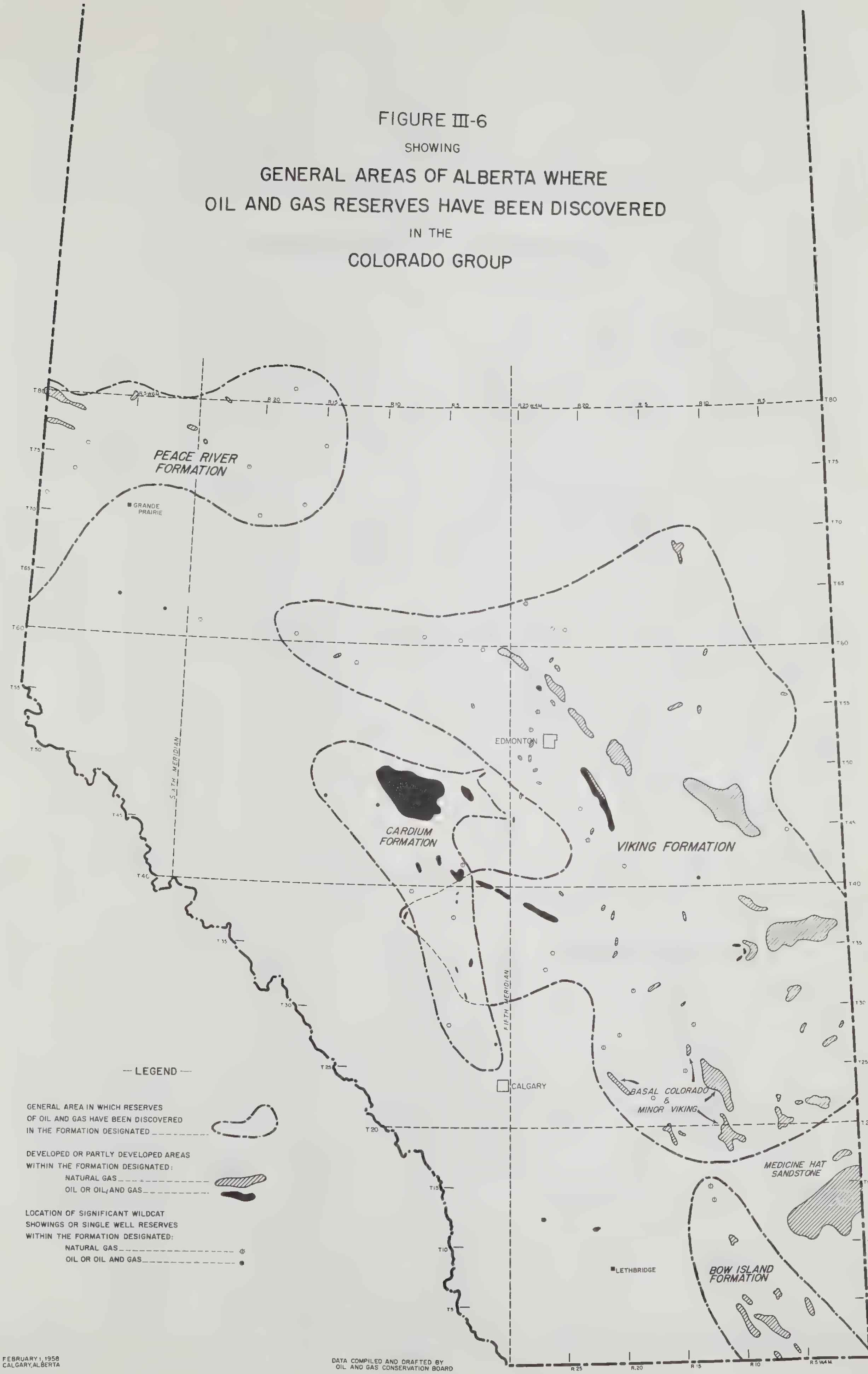
FIGURE III-6

SHOWING

GENERAL AREAS OF ALBERTA WHERE OIL AND GAS RESERVES HAVE BEEN DISCOVERED

IN THE

COLORADO GROUP



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CALGARY, ALBERTA

DATA COMPILED AND DRAFTED BY
OIL AND GAS CONSERVATION BOARD

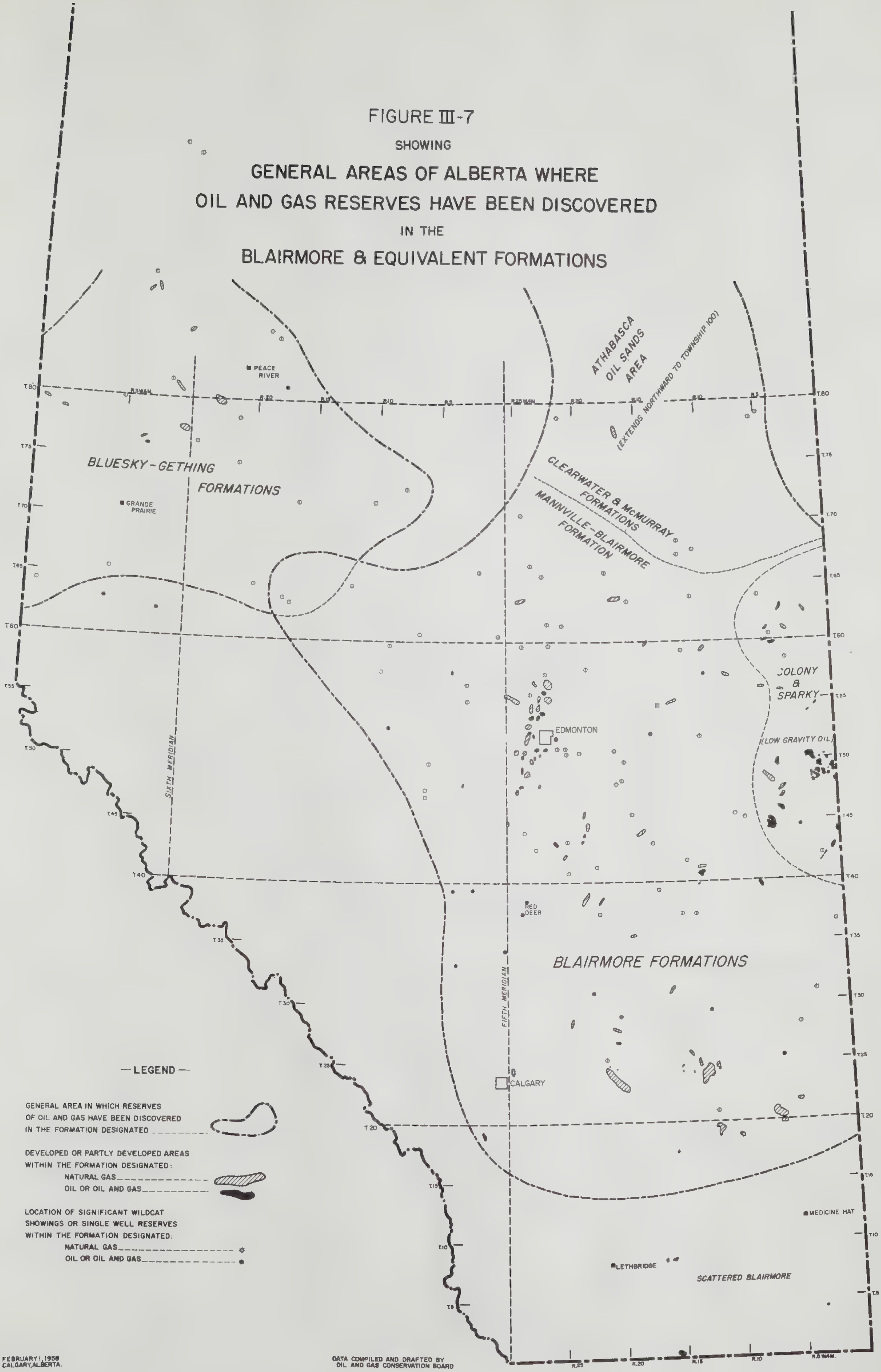

FIGURE III-7
SHOWING
GENERAL AREAS OF ALBERTA WHERE
OIL AND GAS RESERVES HAVE BEEN DISCOVERED
IN THE
BLAIRMORE & EQUIVALENT FORMATIONS

FEBRUARY 1, 1958
CALGARY, ALBERTA.

DATA COMPILED AND DRAFTED BY
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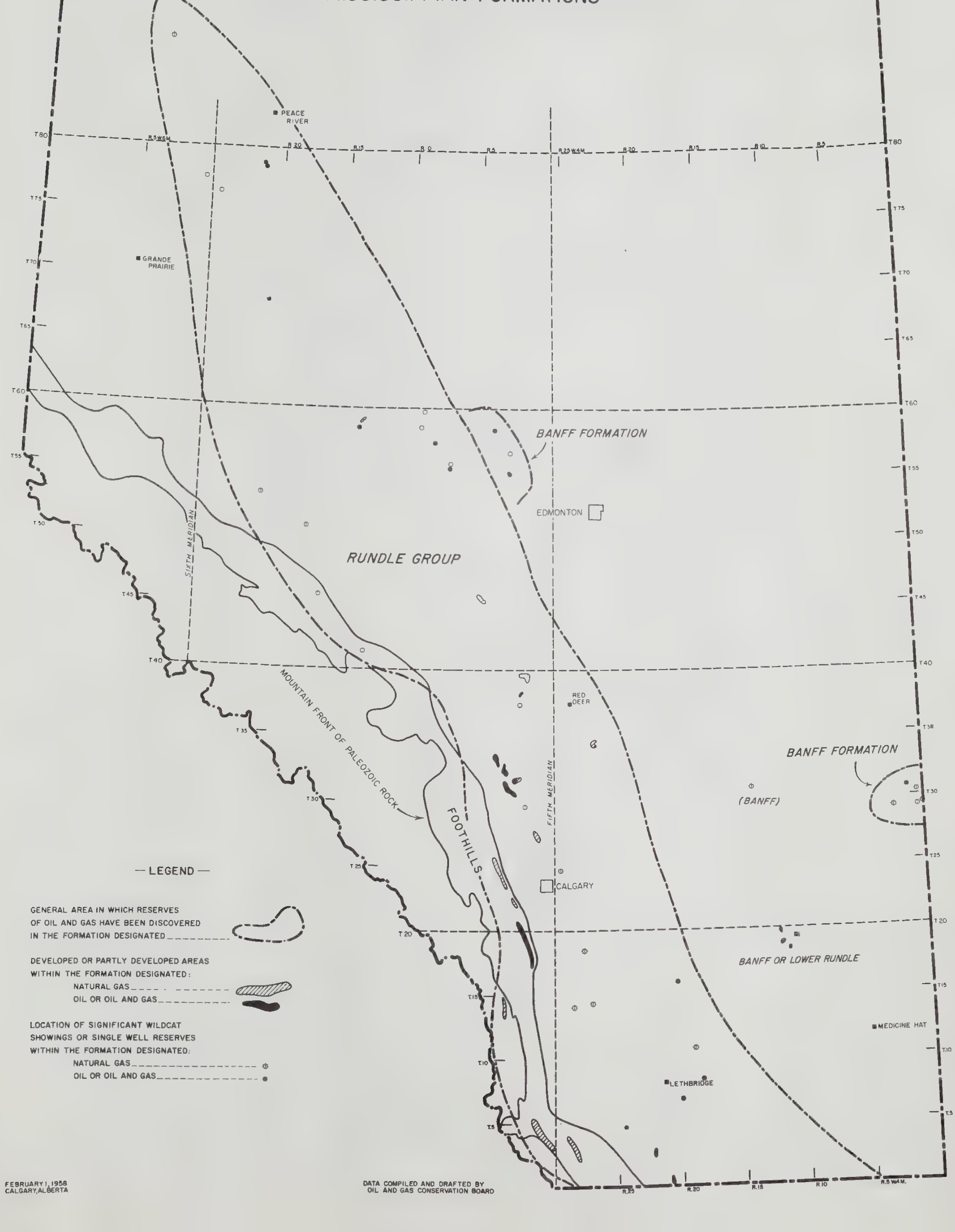
FIGURE III-8

SHOWING

GENERAL AREAS OF ALBERTA WHERE OIL AND GAS RESERVES HAVE BEEN DISCOVERED IN THE MISSISSIPPIAN FORMATIONS



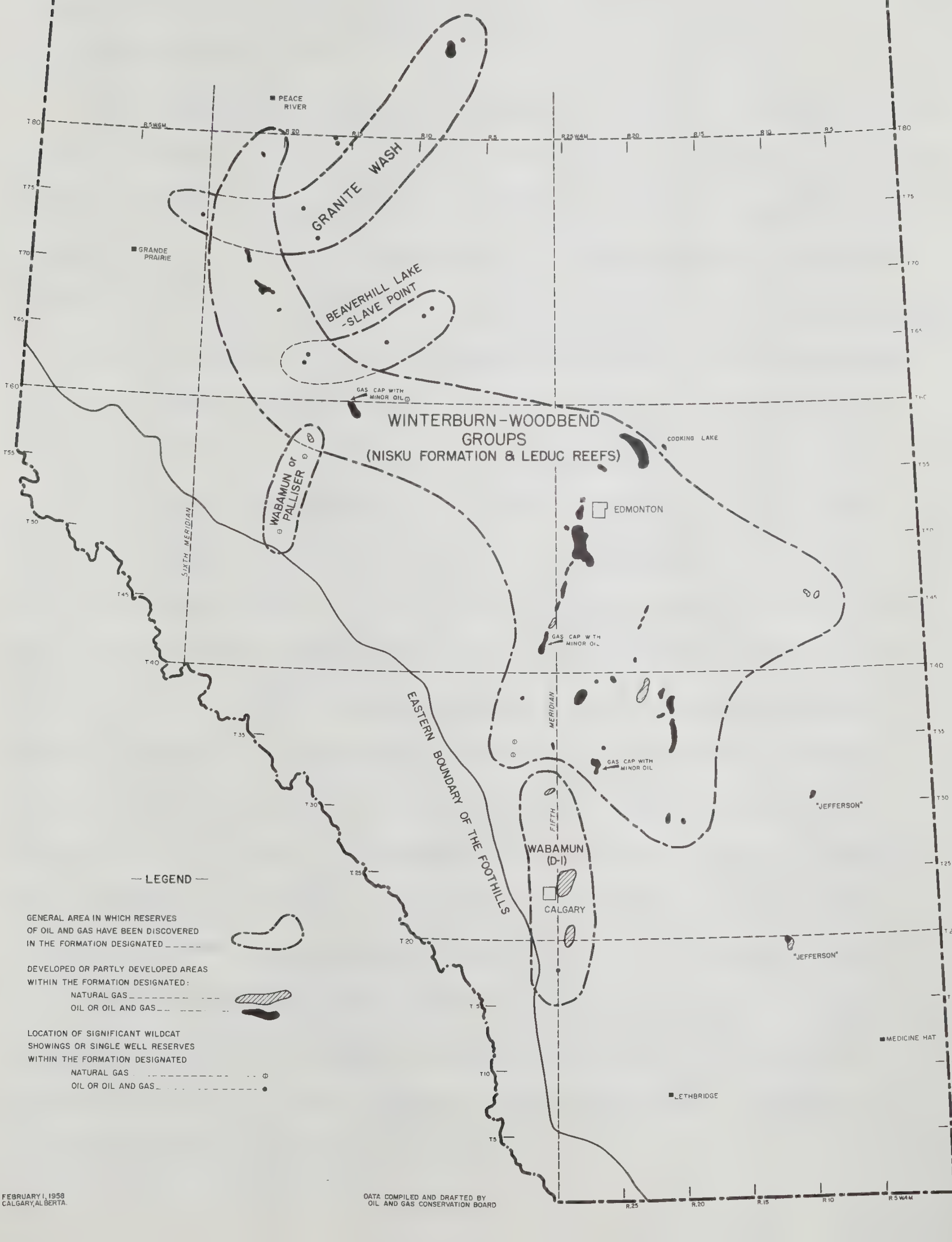
FEBRUARY 1, 1958
CALGARY, ALBERTA

DATA COMPILED AND DRAFTED BY
OIL AND GAS CONSERVATION BOARD

FIGURE III-9

SHOWING

GENERAL AREAS OF ALBERTA WHERE OIL AND GAS RESERVES HAVE BEEN DISCOVERED IN THE DEVONIAN AND PRE-DEVONIAN FORMATIONS



FEBRUARY 1, 1958
CALGARY, ALBERTA.

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Geological Characteristics of the Oil and Gas Fields of Alberta

Oil and gas have been localized by stratigraphic, structural and combined stratigraphic-structural traps within the productive formations of Alberta.

1. Stratigraphic Traps.

Stratigraphic traps are caused by either a change from one type of rock to another or by a variation of porosity and permeability within the same type of rock. When the permeability and porosity of a reservoir formation is terminated in a suitable pattern by these changes, a trap is formed, capable of collecting hydrocarbons that have migrated into the area containing the trap. The regional tilt of a formation may assist this type of trap in localizing an accumulation of oil or gas.

The sizes and shapes of the stratigraphic traps underlying the plains of Alberta are varied. The Cardium reserves and many of the Viking reserves have been localized within wide-spread but thin blanket deposits of sandstone contained within a host rock of shale. Other Cretaceous reserves are contained by small sandstone lenses or by narrow and elongated deposits of sand. Mississippian oil reserves have accumulated in south-western Alberta where a portion of a tilted reservoir formation was decapitated and the area later covered by a layer of impervious rock. Mound-shaped Devonian reefs of porous carbonate rock contain large reserves that are confined to the reefs by surrounding shale. Other Devonian reserves are trapped within a development of porous dolomite contained by a regionally-tilted formation of impervious dolomite.

2. Structural Traps.

Structural traps are caused by the folding, tilting, fracturing or faulting of sedimentary strata. To qualify as a structural trap, it is necessary that these factors alone account for the confinement of the hydrocarbons within the reservoir rock.

In the foothills and eastern mountains of Alberta, the Mississippian oil and gas reserves have been localized at great depths by structural traps produced by intense forces of compression and shearing. Beneath the plains of northwestern Alberta, large gas reserves have been discovered in Cretaceous reservoir formations that were distorted into dome structures by the crustal adjustments of the basement rock. Additional structural traps occur in the Devonian Nisku (D-2) formation where it has been locally warped into a dome structure by differential compaction within a lower formation and where its porosity and permeability are developed over the entire structure.

3. Combination Traps.

Combined stratigraphic-structural traps are caused by a combination of the factors that produce straigraphic and structural traps. Included in this category are those traps that have accounted for hydrocarbons being localized over only a part of the structure, the remaining part being unproductive due to the absence of reservoir rock. The boundaries of such a pool are determined both by the configuration of the structure where it contacts the fluid interfaces and by the position of the reservoir "pinch-out".

Many examples of combined stratigraphic-structural traps occur beneath the plains of Alberta. The most common are the numerous Gething, Blairmore and Mannville pools that have accumulated within lenticular deposits of sand covering a part of a dome or plunging anticline, the latter being associated generally with underlying Paleozoic erosional remnants or reefs.

The facility with which an oil or gas field can be discovered depends upon its depth, areal extent, the type of trap, the geological complexity of the region in which it occurs and the general adaptability of geophysical techniques to its detection. For these reasons, those fields buried deeply in the complicated folds and thrust faults of the foothills are more difficult and expensive to discover than the relatively shallow and wide-spread traps occurring within the less complex formations underlying the plains of the Province.

CHAPTER IV

LOCATION, SPACING, LICENSING AND DRILLING OF WELLS

The spacing and location of wells is regulated by the Drilling and Production Regulations[8]. The normal oil well spacing unit between the Alberta-Saskatchewan boundary and the 5th Meridian is one legal subdivision. The normal oil well spacing unit west of the 5th Meridian is two legal subdivisions, being either the east half or west half of a quarter section. The normal gas well spacing unit throughout the Province is one section.

To obtain a production allowable based on the area of a spacing unit the well must be completed within its target area. In the case of a one-legal subdivision spacing unit, the target area is a central square area with a side dimension of between 330 feet and 660 feet, depending on the depth. In the case of a one-section spacing unit, one has the choice of target areas in each of the central legal subdivisions or in the centre of the section. In the case of other spacing units larger than a legal subdivision, the target area is in a specified legal subdivision.

If a well is completed outside its target area, the area upon which its production allowable is based will be an area less than that of the spacing unit and determined in accordance with the regulations or the spacing unit order.

(8) Alberta Regulation 3/57; Appendix A.

The Board has issued orders creating spacing units other than normal spacing units in a number of fields and areas throughout the Province. The Board believes, with industry, that the trend toward wider spacing generally is sound, and most abnormal units are larger than those that would apply in the absence of a spacing unit order. Some spacing unit orders are applicable for a limited time, and some are not. The orders subject to a time limitation are useful during the earlier operations in a field to permit a more rapid and economical reservoir appraisal, on a spacing pattern that contains larger units and that will permit "in-fill" drilling later if fuller knowledge of the reservoir indicates that the variation from normal units is not justified. Orders providing for abnormal spacing units for unlimited times are made after sufficient knowledge of the reservoir has been gained to prove that adherence to the normal unit is unjustified in the light of drainage characteristics or the economics of field development.

Licensing of Wells

Sections 18 to 32 inclusive of the Oil and Gas Conservation Act relate to the licensing of wells. No well may be drilled without a licence issued by the Minister of Mines and Minerals of the Province and application for a well licence may be made only by a person or

company entitled to the oil or gas. If a well is to be drilled for production of oil or gas the applicant must be entitled, or represent a party who is entitled, to the producing rights in the spacing unit in which the well is to be drilled, or if the well is for some other purpose then the applicant must have the right to drill such a well. Application for a well licence must be submitted to the Board for examination and forwarding to the Minister with the Board's recommendation.

The proposed well location must have been surveyed by a surveyor or competent engineer and plans of the survey, endorsed by the applicant and the surveyor, must be submitted with the application. The survey plan must show the proposed well site in relation to an established land survey monument and also to the boundaries of the spacing unit in which it lies. It must also show all rights of way, building, mines in the same legal subdivision and all bodies of water or other wells in the same spacing unit.

A well for oil or gas may not be drilled within 330 feet of any right of way or permanent building unless the Board considers such a condition is justified. Drilling in the proximity of a coal mine is permitted only after the Board and the Director of Mines are satisfied that reasonable precautions have been undertaken to protect both the mining and the oil or gas operations from foreseeable harm.

Before a licence for an oil or gas well will be issued to an applicant he must have with the Provincial Treasurer a minimum cash deposit of $2,500. If he is to be the licensee of two or more wells the amount of the deposit must be a minimum of $3,500. This deposit is refundable only after the wells for which he is licensee have been abandoned to the satisfaction of the Board.

The deposit is required in order to ensure the proper maintenance and eventual abandonment of any and all wells for which the depositor is owner or licensee and, upon failure of an operator, may be used to defray the cost of having any such necessary work done by the Board(9).

A well licence may be cancelled by the Minister of Mines and Minerals for a contravention of the Act, the regulations, a Board order or a condition of the licence.

Licences may also be amended or suspended by the Minister upon recommendation of the Board.

Application for a well licence must be accompanied by a fee of $25.00 payable to the Provincial Treasurer.

Permits to Operate Drilling Equipment

The Act requires that a party conducting drilling or reconditioning operations of a well must hold a permit from the Board to operate drilling equipment. These permits are issued by the Board for a period of one year and may be cancelled by the Board if, in its opinion, a permittee fails to comply with the provisions of the Act, regulations, or orders thereunder. A permit fee of $25.00 is required.

(9) Section 126 of the Oil and Gas Conservation Act

CHAPTER V

FIELD INSPECTIONS

In order to keep in touch with the wide-spread oil and gas development in the Province, the Board has established nine field areas each containing one office for the personnel who carry out the field inspections within that area. Each field office is in charge of an engineer who may have a staff of from one to six assistants. The make-up of the field staff varies with the requirements of each area but the normal office is composed of the field engineer, one assistant engineer, two technicians and a stenographer or clerk. The field staff by frequent inspections of drilling rigs, wells and production equipment determines if operations are being carried out in compliance with the Board's requirements. The inspector will observe if operations are being carried out in a safe manner; if avoidable waste of reservoir energy or produced fluids is occurring at any well; if surface damage is being kept at a minimum; and if the equipment and installations are such as to allow for proper well testing, the measurement of gas, oil and water, and the obtaining of samples. He will also check to see if measurements of oil, gas and water production are properly made and recorded.

All well abandonments are inspected to see that the well is effectively sealed in and that the land surface has been cleaned up and levelled. In addition to inspections, the field staff collects and processes a great amount of

information on drilling and completion of wells, pressure and temperature data, and other pertinent information, which is forwarded to the main office in Calgary for further studies.

Testing of Wells

Certain basic information is required by the Board on all wells drilled in the Province. This information is obtained by various tests and the taking of samples during the drilling and producing life of the wells. The information thus obtained is utilized by both the Board and industry in their study of oil and gas reservoirs. Without this storehouse of information both the Board and industry would be under a great handicap in any attempt to institute proper conservation measures.

Among other things the Board requires that,

(a) rock cuttings and cores as specified by the Board Geologist be taken on every well drilled;

(b) electric logs or other suitable logs be run on every well drilled;

(c) tests at 500-foot intervals be run on all wells being drilled to determine the amount the hole deviates from vertical;

(d) fluid samples from drill stem test recoveries on wildcat wells be taken and either submitted to the Board for analyses or analysed and a copy of the analyses submitted to the Board;

(e) all gas wells be adequately tested by the back pressure

method either before or shortly after going on steady production. (In the case where a gas producer is located in a field in which allowables are determined for each well, annual tests are required.)

Where a group of oil wells are operated as a battery and the individual wells are not produced into separate storage facilities and the produced fluids are commingled before measurement, which is the usual case, each well must be separately tested at regular intervals, usually once or twice a month.

For every new oil pool discovery a reservoir pressure is measured either by the company or with Board equipment. Reservoir pressure surveys are usually continued at least annually on important discoveries. The Board maintains its own units for the measurement of such pressures, but generally confines its measurements to a check basis.

A representative sample of oil, gas and water, where available, is obtained from every oil or gas pool and analysed by the Board Chemist. This program is conducted by Board personnel to insure standard sampling and analyses.

Many companies do much more testing and analysing than the Board requires, such as running productivity index tests, taking and analysing bottom hole samples, running additional types of logs, and the like. Copies of all such additional information are made available to the Board.

CHAPTER VI

LABORATORY SERVICES

The Board maintains a chemical laboratory in Edmonton for the purpose of analysing samples of oil, gas and water.

Crude oil samples are analysed by the U.S. Bureau of Mines method and the analyses may include the identification of fifteen fractions as to their specific gravity, aniline point, pour point, viscosity, and refractive index.

The laboratory has available a Hyd-Robot Podbielniak-low temperature distillation unit and a new Burrel model K2 unit using the chromatographic method for the analysis of gas samples. An anlysis for helium is also generally made on gas samples.

Water samples are analysed using gravimetric methods throughout including special analysis for bromide and iodide. Bacterial counts are not run.

In general, the Board runs very complete and thorough analyses on representative samples from the producing zone of a designated field, and only minimum analyses for purposes of identification on samples submitted from wells not in a designated field.

Reports of analyses on oil, gas or water samples from a well within a designated field are available to the public immediately, whereas the reports on samples taken from wells outside of a designated field are not made public until one year after the well has been completed or abandoned.

A sample laboratory for the processing and preservation of drill cuttings is maintained in the Board's Calgary office. Companies are required to take cuttings, as specified by the Board Geologist, and ship them to this laboratory. When received the samples are machine washed, packaged and labelled in glass vials. To date, the Board has washed and packaged sample cuttings representing about fifteen million feet of drilling. These sample cuttings may be examined by industry geologists to enable the preparation of geological maps and cross-sections used to facilitate the search for oil and gas.

Cores are selectively preserved by the Board when it is not the intention of an operator to provide such storage. The cores are available to the industry for examination.

At the present time the Board utilizes about 8,600 square feet of floor space for core storage and has an additional 4,350 square feet available for future use.

CHAPTER VII

REGULATION AND DISPOSITION OF OIL PRODUCTION

The Board regulates the rate of production of all crude oil wells in Alberta and seeks to do so on the basis of sound engineering and economic practices and with the intent of preventing waste, conserving oil resources, and maintaining equity.

Waste of oil occurs, in the obvious sense, if it is destroyed through burning or evaporation, or is permitted to seep into or flow over the land. Waste of this type is forbidden by regulations under the Oil and Gas Conservation Act, and proper control, containment, and storage of crude oil is required at all times. Underground waste occurs if recoverable oil is permitted to migrate to another formation from which it cannot be recovered. The Board, with its powers to regulate drilling, completing and abandoning of wells, requires that all fluids in underground strata be confined to their source horizons.

The least obvious but most significant form of waste occurs when economically recoverable oil is left in an underground pool through improper production practices. Producing oil in such a manner that portions of the underground rock are by-passed by encroaching water or gas, and squandering reservoir energy through inefficient production rates are examples of production practices which cause reservoir losses and hence underground waste. The Board

seeks to minimize underground waste of this type by setting a maximum rate of production for each oil well and each oil pool in the Province.

Maximum Permissible Rates

It is well recognized in the oil industry that after sufficient production experience is gained from an oil pool it is possible to establish for the wells in the pool a "Maximum Efficient Rate" (MER) of oil production. The MER of a well or pool is that maximum rate at which production may be taken consistent with sound economics and good reservoir engineering practice. Unfortunately, the necessary experience and data to determine this rate properly are not available early in the life of a pool and recourse must be made to other methods.

Prior to 1950 maximum producing rates in Alberta were established by the Board upon the recommendation of the various pool operators, and on a general judgment basis. During 1950 the Board adopted the concept of a "Maximum Permissible Rate" (MPR) of oil production. The MPR formula was developed by the Board to enable it to set allowables for wells on an equitable basis and on sound engineering grounds early in the life of a pool. Details of the formula may be found in Appendix E. The MPR of wells in a pool is based on the estimated recoverable reserves of the pool and takes into account the maximum rate at which the average well may be produced without either damage to the pool or waste of reservoir energy.

The MPR makes provision for variations in size of spacing units, and for variations in the mechanical producing efficiency of wells in a pool, penalizing those wells and pools where pressure differentials exist or where the production of excessive amounts of gas or water with each barrel of oil indicates poor utilization of reservoir energy.

With certain minor modifications, the Board's MPR formula has been the basis for establishing maximum rates of production for all new oil pools, and many older pools, since its first use in 1950. When there has been sufficient production history to fully determine the characteristics and recovery mechanism of a reservoir, it is the policy of the Board to supplant the MPR with the MER previously referred to, which is based on extensive studies of well behaviour and reservoir engineering mechanics. MER's have been established for some seventeen pools in Alberta, representing just over one half of the recoverable reserves of the Province. The MPR's and MER's of all pools are reviewed by the Board at least once a year at a public hearing.

Economic Allowance

It is recognized by the Board that certain types of marginal and sub-marginal wells cannot always be produced at that rate which will give the optimum physical recovery of oil, since production at such rates may be uneconomic. The Board, therefore, has established an economic allow-

ance related to drilling and producing costs and scaled to depth. This allowance serves as a floor in the MPR calculation. A well is permitted to produce its economic allowance, subject to production penalties if excessive amounts of gas or water are produced along with the oil, even though some loss in reservoir efficiency may result. The Board's economic allowance scale has recently been reviewed at a public hearing and an amended scale(10) reflecting current costs and crude oil prices became effective on January 1st, 1958.

Market Proration

In 1949 the market demand for Alberta crude oil fell below the level of production obtainable under the maximum producing rates then established. There followed several months during which production from various producing pools was prorated to the existing market on the basis of pipe line acceptances. Early in 1950, a number of producers requested that the Board establish an equitable system of proration to market demand. A series of public hearings ~~were~~ was held to consider the matter. The Board, having regard to the several systems recommended, established its "Plan for Proration to Market Demand"(11). This plan was put into effect in December, 1950, and with various modifications, has remained in use since that time.

Each month the Board holds a public hearing at which the crude oil purchasers' nominations for their requirements for the succeeding month, are presented. The Board,

(10) Appendix F.
(11) Appendix F.

on the basis of the nominations and any evidence adduced then determines the provincial allowable for the month. The provincial allowable is then allocated among the pools and wells in the Province; firstly, on the basis of providing an economic allowance for each producing well and, secondly, on the basis of sharing the residual demand (after provision for the economic allowance) in proportion to the pool or well MPR. MER.

As a result of public hearings held in May, 1957, on the subject of the proration plan, the Board has announced that a revised method of proration will become effective in Alberta on January 1st, 1960. After providing for an economic allowance for each well in the Province, the revised plan provides for the sharing of the remaining demand on the basis of MPR minus the economic allowance. The effect of this revised plan is that well allowables will more closely approach constant percentages of their MPR's than under the current plan.

Disposition of Oil

In the complex flow pattern of crude oil from its source beds in the reservoir rock, through the well bore and flow lines to the field storage tanks, thence by pipe line networks to processing and refining centres, and finally to market as a myriad of products, the Board's basic responsibilities terminate at the field storage point. Here safe containment in covered tanks is required, as well as the proper measurement of the oil and the filing of reports thereon.

The Board's responsibilities in the marketing and disposition of crude are discharged when the monthly purchasers' nominations have been translated into the provincial allowable and this allowable has been allocated by Board order between and among the pools and wells within the Province. On the question of regional market supply, the Board takes the position that its monthly proration orders will provide sufficient oil to meet the prevailing demand and that it is the responsibility of the crude oil producers and purchasers to make the necessary arrangements for movement of the crude to the various marketing areas.

Notwithstanding the above restrictions in the Board's responsibilities related to the disposition of oil, the Board and its statistics staff have attempted to keep themselves informed on the Canadian supply position. Each year the Statistics Department prepares for the internal use of the Board an Annual Review of the Oil and Gas Industry with special reference to Alberta. The Review for 1956 is attached as Appendix G. It contains some figures and charts which may be of interest to the Commission. For example, it shows that the Canadian reserves of oil in 1956 were some 18 times the Canadian production and 11.6 times the Canadian demand for crude oil and products. This compares with United States figures of 11.9 times production and 11.3 times demand. The Board will be glad to furnish copies of the 1957 Review as soon as it is prepared.

CHAPTER VIII

REGULATION OF PRODUCTION AND DISPOSITION OF GAS

Board Policy

In the case of gas the general policy with respect to production and conservation remains unchanged from that outlined in a submission by this Board before the Dinning Commission in 1949. This policy is summarized for the different categories of gas by the following excerpts from the submission:

1. Dry Gas

   Complete prevention of production of gas beyond the amount which may be effectively utilized or stored - i.e. complete elimination of waste. Effective utilization may include use as fuel, as chemical raw material, etc. and also use to increase or facilitate the recovery of liquid petroleum in adjacent fields. It is the Board's policy to prevent the operation of any well in a manner which may cause damage to the reservoir resulting in a permanent loss of recoverable gas. This is satisfied by good engineering practice, by common sense operation and by avoiding excessive withdrawal rates.

2. (1) Wet Gas not Associated in the Reservoir with Commercial Quantities of Oil

   The policy with respect to gas of this type is to permit production as in the case of dry gas fields but

to require the recovery of the economically recoverable liquid hydrocarbons before disposition of the gas.

(2) Wet Gas Associated in the Reservoir with Commercial Quantities of Oil

(a) Solution Gas

(i) The prevention of "excessive wastage" of gas. Ideally, the Board would prefer no waste of gas but it recognizes

A. that produced solution gas aids the lifting of oil from the reservoir and in this sense has undergone some "use";

B. that up to a certain volume and/or pressure it may be uneconomical to gather gas which is unavoidably produced with oil. This is usually the case early in the life of a field when its productive limits and potential productive capacity are unknown.

For these reasons the Board tolerates a "reasonable waste" of solution gas when such waste accompanies the economic production of liquid petroleum but not beyond the point where gathering of the gas is reasonably economical.

(ii) For such solution gas as can be economically gathered, the policy is to require the removal of the economically recoverable liquid

hydrocarbons. The value of recoverable liquid hydrocarbons is usually a major factor in determining the volume and/or pressure at which solution gas can be economically gathered and processed.

(iii) The solution gas after removal of recoverable liquid hydrocarbons is termed residue gas. The policy of the Board is to require complete effective use or storage of this gas. While effective use includes use as fuel, chemical raw material, etc., the Board is particularly concerned in seeing that, when economical and feasible from an engineering viewpoint, part or all of this residue gas be employed to increase the ultimate recovery of liquid petroleum from the reservoir.

(b) Gas Cap Gas

Production of gas of this type need not necessarily accompany the production of liquid petroleum. The general policy of the Board is:

(i) to prevent production of gas cap gas for market so long as this gas, in the reservoir, is economically aiding in the recovery of the liquid petroleum underlying it;

(ii) to permit production of gas cap gas for the removal of liquid hydrocarbons so long as the residue gas obtained is returned to the

reservoir and so long as the well is not operated in a manner which may cause damage to the reservoir resulting in a permanent loss of either recoverable oil or gas. The requirement of returning gas cap residue gas to the reservoir would be Board policy so long as this gas could economically aid in the recovery of the underlying liquid petroleum.

Present practice in Turner Valley is to permit production of gas cap gas in accordance with the Brown plan and for removal of liquid hydrocarbons and effective use of the residue gas. This plan, inaugurated several years after production from gas cap wells had started, represents a compromise between true conservation and unrestricted flow from the gas cap. Such a compromise is required because most of the gas cap wells were drilled and production was started before the engineering concepts of conservation were well developed. Furthermore, many of the Turner Valley wells which are drilled into the gas cap cannot reach the underlying oil which, because of the dip of the structure, underlies other leases. In such cases the practice of complete conservation is virtually impossible unless the entire

field is operated as a unit. The present policy of the Board towards gas cap production from Turner Valley or from future similar fields is to promote and assist efforts which would lead either formally or informally to the unit operation of the field and then to follow the general "gas cap" policy outlined above.

(3) Gas Condensate Gas

The present policy of the Board with respect to gas condensate gas is;

(a) to prohibit the regular production of reservoir fluid pending detailed analyses of samples of the reservoir fluid and determination of the engineering and economic importance of maintaining reservoir pressure;

(b) if analyses and study should show no danger of retrograde condensation or no serious economic loss attending retrograde condensation, the policy of the Board would be to treat the fields as (1) "wet gas fields not associated with liquid petroleum", and to permit production for recovery of liquid hydrocarbons and effective utilization of the residue gas;

(c) if analyses and study should show danger of retrograde condensation and serious economic

loss of recoverable liquid hydrocarbons attending pressure decline below some critical value, the policy of the Board would be to permit the production of reservoir fluid for recovery of liquid hydrocarbons, but (if feasible from the engineering and economic viewpoint) to require the reinjection of the residue gas into the field for the purpose of pressure maintenance. This method of operation is often called "cycling" or "recycling" but is essentially pressure maintenance. The effect of this policy would be, as in the case of gas cap gas, to defer the time when the residue gas from the gas-condensate fields would be available for market.

Gas Allowables (Non Associated Gas)

Alberta producers have been advised by the Board that gas production allowables would only be set for wells in pools or fields where reservoir conditions or equity considerations made it necessary. The presence of underlying water may require restriction in maximum daily rate of production to prevent water coning and thus premature abandonment of a well. Continued unequal withdrawals from wells on adjoining tracts ~~having~~ tapping the same reserves could result in migration and loss of reserves by an owner. To minimize these occurrences the Board has designed a Maximum Daily Allowable (Q_M),

based on the deliverability characteristics of the well and an Annual or Daily Average Allowable (MPR_G) based on the reserves of gas underlying the well's spacing unit. The details of the allowable calculations are contained in Board circular letters dated September 29th, 1954, May 31st, 1955 and December 13th, 1956[(12)]. To date, allowables have been set in two gas fields - Medicine Hat and Fort Saskatchewan. The data used in calculating allowables for these fields are obtained from the operators and other interested parties at annually scheduled hearings.

Gas Allowables (Associated Gas)

Gas produced unavoidably with oil is restricted by the gas-oil ratio penalties governing oil production. For pools having a thin oil column underlying a gas cap and whose wells become severely penalized due to high producing gas-oil ratios, the Board has designed the Combination "Gas-Oil" Allowable scheme. This is a scheme whereby, provided all produced gas is conserved, an operator may produce one half of an economic oil allowance and all gas associated with it. Details of the scheme are outlined in Board circular letter dated November 2nd, 1955[(13)]. There are three or four pools producing under this allowable scheme at present and it is expected that the scheme will play a large part in the future development of some fields for which there presently is no gas market, and therefore, cannot qualify for the allowable.

(12) Appendix H
(13) Appendix H

Gas Conservation

The conservation of gas produced unavoidably with oil is one of the most difficult problems the Board has to contend with. The Board realizes that early in the producing life of an oil field that a certain amount of gas wastage must be tolerated. However, it believes that when a field has been reasonably delineated and a reasonably accurate forecast of gas production can be made that the gas should be gathered, processed and marketed or stored if it can be established that this may be done without the producers being "out-of-pocket". The definition of "out-of-pocket" is, of course, a bone of contention between industry and the Board.

The Board thinks that gas should be conserved if the cost of the project can be repaid over the producing life of a field and yield a utility rate of return on the investment even though this means that a producer may get nothing for the gas.

There are, of course, many intangibles to be considered, particularly in estimating the revenues from a conservation project. It is difficult to forecast accurately the annual production of gas as this is tied to oil production which varies according to market demand and the provincial potential production. Future prices for natural gasoline, LPG's - the by-products of processing, and residue gas also are difficult to gauge. While the market for these products is depressed at the present time, the Board believes an

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optimistic view should be taken on a long term basis.

With respect to all gas processing plants it is most important to consider the matter of the plant operating load factor. Plant capital and operating costs are high and it is essential to operate the plant at as high a load factor as possible to reduce unit operating costs.

When the Board considers that steps should be taken to conserve the gas, it notifies the operators concerned and invites them to attend a meeting at which the Board's production forecasts and economic studies and those of the operators are thoroughly discussed. The operators may agree to construct the necessary facilities, but if this is not the case and the Board firmly believes the gas should be conserved, it issues an order requiring that the gas produced with oil be conserved by a certain date and failure to comply means the shutting down of wells.

Any plans for the gathering and processing of gas, including the specifications of any processing plant, must be approved by the Board under section 38 of the Oil and Gas Conservation Act. The Board usually holds a public hearing to consider the project. The approval may contain terms and conditions with respect to the percentage of produced gas to be gathered and processed, percentage recovery of by-products required and facilities required for storage or other disposal of products.

CHAPTER IX

SECONDARY RECOVERY

There is no known economic process by which all of the oil in porous rock may be recovered. Five groups of factors determine the fraction of the initial oil in place which may be obtained:

1. Reservoir rock properties, e.g. porosity, permeability, structural position and thickness;
2. Reservoir fluid properties, e.g. viscosity, pressure, gas saturation, phase and component distribution;
3. Drive mechanism, e.g. solution gas, gravity drainage, water drive;
4. Method of production - well completion techniques, spacing of wells, rate of withdrawal;
5. Economics - drilling and completion costs, production costs, taxes, price of oil.

The degree of recovery realized from an oil or gas accumulation depends on the extent to which knowledge of these factors, and of their interdependence, is intelligently utilized. Further, the more accurately the factors comprising each group are known, the greater is the likelihood that optimum methods will be used to obtain maximum recovery. The importance of obtaining accurate data in all phases of oil exploration and development cannot be overemphasized.

As previously mentioned, oil does not, by itself, travel to the well bore. Some form of energy is required to move it

through the rock, and when the energy available has been dissipated, whether efficiently or otherwise, no further oil may be produced. In the early days of the oil industry only a small fraction of the original oil in place was recovered from pools. The reasons for this are important. Lacking an agreement or requirement for orderly drilling and production, each oil property owner, for his own protection, engaged in a race with his neighbor to drill as many wells and produce as much oil as possible. Much waste of money and equipment occurred through overdrilling and tremendous losses of oil resulted, both on the surface as a consequence of over-production, and in the reservoir through minimum utilization of reservoir energy. Thus the "law of capture" and ignorance of the relationship between production rate and ultimate recovery fostered the inefficient and often deliberate dissipation of natural energy forces in most of the early-developed oil pools.

As the industry matured, it was found that some of these energy depleted pools could be revitalized by the introduction to the formation of gas or water under pressure thereby providing an artificial source of energy ~~whi~~ch move~~d~~ additional oil to the well bore. The term "secondary recovery" came into existence at that time to describe such processes, and "primary recovery" was used in reference to that phase of production wherein only natural forces were used. With further experience, it was found more beneficial to

artificially supplement the natural energy forces early in the life of a pool, rather than to await the completion of the primary recovery phase. Such augmentation of reservoir energy, now a well recognized recovery-improving technique in the industry, is still often referred to as "secondary recovery", although its original connotation has been lost. Other terms - "pressure maintenance", - "water flood", "gas injection", etc. are also used to describe certain forms of artificial supplementation of reservoir energy but none of them are completely definitive of the various processes used. For the purposes of the following comments, the phrase "recovery stimulation" will be used, since all the various schemes for injection of gases and liquids are predicated on improving the recovery of oil and gas from the reservoir rock.

Recovery Stimulation

From the preceeding discussion, it will be apparent that a sixth group, Methods of Recovery Stimulation, must be added to the five groups of factors which determine the amount of recovery of oil from a pool. Oil recovery stimulation is receiving ever increasing study in the industry as its benefits of increased reserves and attractive economics become well realized. According to a recent survey made in the United States by the Interstate Oil Compact Commission, an increase in recoverable oil of over four billion barrels can be attributed to recovery stimulation processes used in "stripper" wells alone, and these stripper well pools represent only about

20 per cent of the total United States reserves. Results of recovery stimulation processes show that recoveries may be increased to two or three times that expected under primary means, and there are producing pools where it is only through such stimulation that the recovery of any oil can be made economic. It has therefore been a matter of paramount importance in the exploitation of Alberta's oil and gas that the Oil and Gas Conservation Board should endorse and promote recovery stimulation in the Province.

Methods of Recovery Stimulation

Most methods of recovery stimulation in oil fields have the same basic feature: the introduction under pressure of a fluid, either gaseous or liquid, through one or more drilled wells to the oil bearing formation at a point within, or in pressure communication with, the oil saturated portion of the formation. The injected fluid moves from its point of injection, which has the higher pressure, through the formation to the areas of lower pressure - the bore holes of producing wells. In its passage it flushes ahead of it, and also carries along with it, the oil in the rock pores. Water is one of the most commonly used injection liquids because of its low cost, abundant supply, ease of handling, and similarity in flow characteristics to crude oil. Another common injection fluid is natural gas since it is often available in considerable quantities in association

with, or as a by-product of, oil production. Other materials such as air, liquefiable petroleum gases and carbon dioxide have also been used for injection purposes, either by themselves or in conjunction with natural gas or water.

Laboratory experiments on samples of the porous rock from a reservoir give valuable data as to which fluid, or combination of fluids, will most efficiently flush the oil from the rock pores. These data can then be related to information on availability of the fluid, the economics of its injection and the structural configuration of the reservoir rock, to determine the optimum approach to recovery stimulation.

An important feature of recovery stimulation through fluid injection is the location in the reservoir at which the fluid is injected. Being heavier than oil, water is commonly injected into a part of the formation that was originally water saturated, usually immediately beneath or in the down-structure flanks of the oil pool. Its effect is then to supplement an existing water drive and to extend the region being swept by water. Also, water is often used in a pattern flood, wherein water is injected into the oil zone through alternate rows or staggered arrays of wells for the purpose of laterally "flooding" the oil in the formation toward the producing wells. Such pattern floods are variously termed "five-spot", "nine-spot", "line-drive", etc. If gas is the injected fluid, it is usually compressed and introduced to

the crest of the reservoir structure where it may add to the amount and pressure of gas cap already there, or may form a "secondary" gas cap if none previously existed. Like water, gas is also used in the horizontal displacement of oil in pattern injection flood projects.

Of particular interest at the present time is some of the experimental work being carried out in the use of liquefiable petroleum gases, such as propane or butane, as injection fluids (miscible flood). Laboratory experiements suggest that extremely high recoveries may be realized through the use of such fluids

Administration of Recovery Stimulation

Alberta's Oil and Gas Conservation Act (14) empowers the Board to require that schemes for recovery stimulation be put into effect in order to prevent waste, and also specifies that no such scheme shall be proceeded with unless the Board has approved it. Where it can be demonstrated that additional recovery of oil can be attributed to the scheme, the MPR's or MER's of the producing wells would be increased accordingly to reflect the improvement in recovery. Within this policy the operators of wells in a pool under flood may look forward to increased allowables and improved income to defray the very considerable capital outlay which is often necessary to put a recovery stimulation plan into effect.

(14) Appendix A1 - see Section 37 and 38

Where reservoir engineering studies made by the Board's staff suggest that a scheme of recovery stimulation in a pool would increase the economically recoverable oil or prevent waste, the Board has held informal discussions on the matter with the pool operators and in most cases this has resulted in a voluntary scheme being put into effect. Where necessary the Board, after public hearing, has ordered that a suitable scheme be initiated.

Recovery Stimulation in Alberta

There are a wide variety of full scale recovery stimulation schemes presently under way in Alberta including gas and water injection of various types. In addition, several other schemes have been approved by the Board and are in various stages of preparation. Two experimental schemes using liquefiable petroleum gases and solution gas have been commenced in the Pembina Cardium pool, and one small scale experimental water flood has been in effect for some years in the Turner Valley Field, with good results. At the end of 1957 the recoverable reserves attributed to seven gas and four water injection schemes increased from about five hundred million barrels to seven hundred million barrels, an increase of some two hundred million barrels or $6\frac{1}{2}$ per cent of the net recoverable reserves of the Province at that time. It is expected that this figure may be doubled in the next two or three years as additional projects prove their efficiency.

Finally, it should be pointed out that there are several dozen projects in operation throughout the Province where the water and excess gas that is produced with oil is being returned to the pool from which it is produced. While such schemes are not thought of as recovery stimulation projects but rather as gas conservation or water disposal schemes, they are in fact beneficial to a small degree.

CHAPTER X

POOLING AND UNIT OPERATIONS

"Pooling" as used here and in the Oil and Gas Conservation Act means the combining of tracts that are within a spacing unit and that are subject to different ownership so that they may be operated as a unit to permit drilling and production within the spacing unit. "Unit operation" as defined in the Act means the operation in accordance with a scheme or plan for combining the interests of all owners in a common source of supply of oil or gas in any field, pool or part thereof so that the operation may be conducted as if there were only one operator and one tract, and the cost of the operation and the oil or gas produced thereby are distributed among the owners or tracts according to a formula or a schedule of participation. Thus, the differences between the two are that pooling is on a spacing unit basis and unit operation is on a pool-wide basis and that their objects may be different. Each, however, has the effect of a union for certain purposes of interests in property and each has the effect of modifying leases so that wells required to be drilled may be drilled upon adjacent property within the unit and so that the production used as a basis for royalty payment is altered.

In Alberta, as in most jurisdictions, the operator must have the right to produce oil or gas from all of the spacing unit before he can drill or operate an oil or gas well. Most

oil and gas leases now contain a clause entitling the lessee to pool the oil and gas rights covered by the lease with others to make up the spacing unit. Sections 73 and 74 of the Oil and Gas Conservation Act, however, have provisions for compulsory pooling, which are necessary in cases where a lease does not contain a pooling provision or where the lessees or one of them does not agree to the pooling. (An alternative in some cases is an order making a special spacing unit that would comprise only part of the normal spacing unit.) An order providing for compulsory pooling would not alter the ownership of either the lessors or the lessees in tracts, but would combine their interests for the purpose of drilling and production and provide for apportionment of the costs and expenses and the allocation of production to various tracts. Normally, the apportionment and allocation within a spacing unit are on a simple acreage basis. An order of the Board providing for compulsory pooling requires the approval of the Lieutenant Governor in Council.

A unit operation combines the interests of all the owners, both lessors and lessees, within the unit area. The object is to make possible some recognized and approved conservation procedure such as secondary recovery, underground storage or a more economical program of development of the field. While unit operation is generally accepted as desirable in a proper case, it met considerable opposition in earlier years with the principal objection being that it

tended to eliminate the smaller operators from field operations.

Under section 72 of the Oil and Gas Conservation Act an agreement among owners for a unit operation requires the approval of the Board before it is put into effect. In addition, sections 75 to 82 contain provisions that may be put into effect upon proclamation of the Lieutenant Governor in Council and that would empower the Board, with the approval of the Lieutenant Governor in Council, to order, on a compulsory basis, a unit operation.

While most of the advantages of the unit to the operators are obvious, it is sometime necessary to work for years before a unit operation agreement can be concluded and quite often such an agreement is never concluded. The difficulties as far as operators are concerned often centre on the basis of participation in the production. The same difficulty is in the way of the agreement of royalty owners and in that case there is also the reluctance to accede to variation in the leases which might prejudice them. If a compulsory unit operation order were made, its provisions would name the unit, define area prescribed, provide that the ownership of the various tracts is unaltered, combine the interests for the purpose of unit operation, provide for allocation of production, provide for an operating committee and the naming of a unit operator, provide for adjustment for investment in existing wells and installations and the share of

unit expenses, and contain various other provisions covering related matters as plan of operation, the right of various owners to information, audits, title information and disputes, etc.

The Act stipulates that a compulsory unit operation order shall not come into effect until it has the consent of the owners of the drilling and producing rights in 75 per cent of the unit area and the consent of the owners of the head lessor's royalty interests in 75 per cent of the unit area.

CHAPTER XI

GAS AND BY-PRODUCT UTILIZATION

Section 45 of the Oil and Gas Conservation Act provides that "no gas produced in the Province shall be used or consumed in the Province for any purpose other than for gas lift, repressuring, recycling, pressure maintenance, or for light or as fuel, until a permit authorizing its use or consumption for another purpose is granted by the Board".

The purpose of this section is to prevent the inefficient or improvident use of gas including liquid hydrocarbons and also to guard against public nuisance (e.g. a carbon black plant using the inefficient channel process blankets the surrounding country with black soot).

The manufacture of carbon black is one of the uses which requires a permit. Until recently, the chief source of raw material for the manufacture of carbon black was natural gas. Since the cost of raw material with respect to capital and labour costs is relatively high, the industry was dependent on cheap natural gas supplies which, due to location or other circumstances, could not be used for other purposes. The Board has been prepared to give favourable consideration to an application to construct a carbon black plant in Alberta provided that an efficient process was employed. A few companies investigated the possibility of establishing a carbon black plant in Alberta in the earlier part of the decade but rising prices of natural gas and technological

changes in the rubber industry have detracted from the use of gas for this purpose. The advances made in the use of carbon black manufactured from oil have permitted the establishment of such plants close to markets and further reduced the economic feasibility of establishment of a plant in Alberta. An oil black plant now is in operation in Sarnia, Ontario.

Natural gas and its by-products currently are being used as chemical raw materials in five large plants in the Province. Two of these produce ammonia based fertilizers as primary products while a third produces ammonium sulphate as a by-product. The versatile plastic polyethylene is produced in the fourth plant and cellulose acetate fibre and organic chemicals are produced in the fifth.

The large and increasing reserves of wet gas in Alberta assure the Province of an abundant supply of both the liquefiable petroleum gases (ethane, propane, butanes, etc.) and sulphur as raw materials for the petrochemical industry. Extensive growth in the manufacture of high unit-value petrochemical products such as polyethylene, is anticipated. The distance from Alberta to large consuming markets and the high freight rates, however, seriously militate against the economic production of low unit-value or bulk products. The plans of Polymer Corporation to manufacture butadiene from butane in a plant to be located near Red Deer are indicative of the future. Other such "raw-material oriented" industries producing plastics and textile and other intermediates will undoubtedly be attracted

by Alberta's plentiful and low cost fuel and raw materials.

Propane is widely used as a fuel in rural homes and communities in Western Canada. A more recent use for both propane and butanes has been as injected fluids in oilfield pressure maintenance operations. Natural gasoline is used as a blending stock in refinery operations. A large obstacle in the path of orderly marketing of propane and butanes is the three to one winter to summer ratio of fuel requirements of the market area served and the higher rate of summer over winter production. Due to the extremely high cost of surface storage facilities for these products (approximately $1.00 per gallon) it is necessary to reinject them into a producing formation or to flare them. The development of suitable underground storage, where products stored in the summer months could be withdrawn and used without further processing to meet increased winter demands, would greatly aid Alberta LPG marketing.

Natural gas has been marketed in Alberta since the turn of the century and sales have increased steadily as our cities and towns have grown in size and as more and more communities have been served. While a large amount of industry has developed in the last decade, a substantial portion of the total Alberta requirements for natural gas is for domestic and commercial consumption. Due to the severity of Alberta winters, the ratio of winter to summer heating requirements is high, resulting in an unusually low load factor market. The overall Alberta load factor

for last year was estimated to be 45 per cent. In line with good conservation practice, the local utility companies have endeavoured to give priority in the market to oilfield gas to prevent flaring or reinjection. In some cases this has required the complete closing in of dry gas fields in the summer months.

The Board has taken a particular interest in the supply of natural gas to small communities within the Province. Its staff has made many detailed studies of the engineering and economic feasibility of providing gas service to towns and villages from the nearest gas wells or gas transmission lines. In some cases it has been possible to show that gas could be supplied in competition with alternative fuels and to assist the communities in arranging for gas service. In other instances it has been demonstrated that the cost of gas would not make it attractive to the potential consumer when compared in cost with coal, oil or propane. It has been suggested in these cases that the communities would do better to wait on the chance that further drilling or the construction of additional gas transmission lines would provide gas at a lower cost. A waiting period already has benefited some communities.

The Board also offers advice on the technical and economic aspects of gas supply to the Board of Public Utility Commissioners when that Board considers gas franchise applications.

Some markets outside the Province now are being served with gas released under the provisions of the Gas Resources Preservation Act. Generally the gas used to serve extra-

provincial requirements will be produced at relatively high load factors due to the nature of the markets being served. The matter of gas "export" is discussed more fully in the next chapter.

CHAPTER XII

REMOVAL OF GAS FROM PROVINCE

Gas produced in the Province may be removed from the Province only if the Board has issued a permit authorizing its removal under the Gas Resources Preservation Act, 1956[15]. The intent, purpose and object of the Act, as expressed in section 3, is "to effect the preservation and conservation of the oil and gas resources of the Province and to provide for their effective utilization having regard to the present and future needs of persons within the Province".

Any person who produces, acquires or has contracted for gas and intends to remove it from the Province may apply for a permit. Upon receipt of the application and such information as it requires, the Board notifies the applicant of the time and place of hearing and its requirements for giving notice of the hearing.

After the hearing, the Board may, with the approval of the Lieutenant Governor in Council, grant a permit subject to prescribed terms and conditions, refuse the permit or defer consideration of the application. The Act prohibits the granting of a permit unless the Board is of the opinion that it is in the public interest to do so, having regard to the present and future needs of persons in the Province and to the established gas reserves and trends in growth and discovery of reserves in the Province.

(15) Statutes of Alberta, 1956, c.19; Appendix B

The terms and conditions of a permit may stipulate, inter alia, the period of the permit, the sources of gas, the quantities and rates of removal, conditions under which removal may be diverted, reduced or interrupted and the requirement to supply communities or customers within the Province under reasonable conditions. The Board may, upon a hearing, reconsider a permit and make such order thereupon as the Lieutenant Governor in Council approves. Unless the permittee has applied for the reconsideration he is entitled to sixty days' notice of such hearing.

The Act empowers the Lieutenant Governor in Council to make regulations to facilitate the adminstration of the Act and to place special hydrocarbons (LPG's or bottled gas) under regulations instead of the provisions of the Act. Only the latter power has been exercised.(16)

The first public hearing held by the Board under the provisions of the Act(17) commenced in November, 1949. Individual and joint hearings of six separate applications by different companies for the removal of gas from the Province culminated in the Board recommendation to the Lieutenant Governor in Council in March, 1952 that one of the applicants Westcoast Transmission Company Limited, be permitted to export gas under certain terms and conditions. The details of the Board's recommendations are shown in the Report to

(16) Alberta Regulations 6/57; Appendix B2
(17) The Gas Resources Preservation Act, S.A. 1949 (2nd Session) c.2, in substitution for which present Act was enacted

the Lieutenant Governor in Council dated March 29th, 1952. Additional hearings have been held since that date and have resulted in the Board's recommendations that other companies be permitted to remove gas from the Province. In all, five Reports (18) to the Lieutenant Governor in Council have been made by the Board. The following is a summary of the existing permits granted by the Board to date:

Permittee	Maximum Daily MMCFD	Maximum Annual BCF	Total Authorized Withdrawal BCF
Peace River Transmission Company Limited	6	0.6	13
Peace River Transmission Company Limited	7	1.0	20
Westcoast Transmission Company Limited and Westcoast Transmission Company (Alberta) Limited	190	56	1080
Canadian Montana Pipeline Company	100	20	- *
Saskatchewan Power Corporation	83	18	223
Trans Canada Pipe Lines Limited	620	210	4350
Total	1006	305.6	5959

* All the gas from Black Butte, Comrey, Manyberries, Pendant d'Oreille and Smith Coulee fields. Reserves in these fields are presently estimated at 273 billion cubic feet.

(18) Appendix L

At the public hearings the Board currently requires the applicant to present in support of the application exhibits and verbal testimony with respect to all phases of the proposed projects, including the following:

1. Evidence that at least 80 per cent of the gas proposed to be removed is under contract to the applicant and particulars of each of the gas purchase contracts;
2. The location and description of the pools, fields or areas within the Province from which it is proposed to remove gas;
3. The estimated reserves of gas in each such pool, field or area and the geological, engineering and other data used in the estimation;
4. The deliverability characteristics of the wells in each such pool, field or area and the geological, engineering and other data used in their determination;
5. A detailed deliverability schedule showing how it is planned to produce the quantities of gas proposed to be removed from the Province during the full period of the removal from each pool, field or area;
6. Evidence that the proposed removal of gas is in the public interest, having regard to
   (1) the present and future needs of persons within the Province, and
   (2) the estimated reserves and tr~~ans~~ends of discovery and growth of reserves of gas in the Province;

7. The route and design details and capital and operating costs of the pipe line facilities required to implement the proposed removal;

8. ~~Cost~~ details with respect to the marketing areas to be served beyond the Province and the amounts of gas to be used for domestic, commercial and industrial purposes;

9. Particulars of the contract between the applicant and the purchasers of the gas to be removed from the Province through facilities of the applicant;

10. Particulars of the method of financing the proposed facilities.

At the conclusion of a hearing, the Board reviews the evidence submitted and also the work of its own staff with respect to the reserves of gas, the present and future needs of persons in the Province and methods of supplying the requirements.

The Board in its Interim Report in 1951 made the following recommendation concerning the protection of the present and future needs of the people of the Province:

> "In view of the most favourable prospects of the Province for the discovery of additional extensive gas reserves and in view of the possibility of the development of alternative forms of fuel and energy, the Board believes that the Province will be adequately protected if sufficient reserves of pipe line gas are provided to maintain the supply and

deliverability for thirty years."

X

The Alberta Government concurred in the Report. Since that time the thirty year requirement has been adhered to.

The problem of supplying requirements requires deliverability studies - the selection of various pools and areas whose gas reserves may be produced economically to meet the requirements of a market at the time and in the quantities required by the market. There may be considerable variation between average day requirements and peak day requirements in a market - in Alberta the average consumption is approximately 45 per cent of the peak day. In preparing illustrative deliverability schedules, it must be shown how both annual and peak day requirements may be met.

The matter of selecting the reserves that can best meet the requirements of any substantial market is a complex one involving the preparation of many alternative schedules, each based on a great deal of detailed study and calculations. Consideration must be given to proximity of the reserves to the market or a main transmission line, the size of the reserve, its reservoir characteristic and its ability to produce in accordance with sound conservation practice.

The nature of the gas itself, whether it be dry gas or wet gas either associated with or non-associated with oil, is important in determining deliverability. It is the Board's policy to give, where practical, first market priority to gas produced unavoidably with oil and second priority to

processed wet gas produced from wet gas and condensate fields. Gas processing plants are costly, and in order to operate economically must have a throughput load factor of not less than 70 to 80 per cent. With a large proportion of our reserves being wet gas, the ideal way to meet requirements would be to use wet gas for basic requirements and dry gas for peak loads.

In scheduling fields in a deliverability schedule, the Board follows a policy of assigning to each utility system the reserves of gas which are most suited to that system having in mind distance from existing facilities and the type and deliverability characteristics of each reserve. In this manner it should be possible to reflect the lowest cost of gas to local consumers.

It is only after trying, by trial and error method, various combinations of the different types of reserves that a final deliverability schedule can be compiled indicating how the requirements of the Province can most efficiently be met and how any surplus reserves can be used to meet the requirements of an applicant for "export". Of course this final schedule can only be illustrative and would be subject to change with the development of additional reserves and changing markets.

After reviewing the evidence adduced at the hearing of an application and the comparative studies of its staff, the Board submits a report to the Lieutenant Governor in Council

fully outlining the matters considered, its conclusions and the disposition it proposes to make of the application.

As an illustration of the analyses included by the Board in its report to the Lieutenant Governor in Council reference is made to the report (19) dated November 24th, 1953. Appendix A of the report enlarges upon the findings of the Board concerning the current gas reserves of the Province and tabulates the reserves of the more important fields. In Appendix B is found a study supported by graphs showing the trends in exploration and the growth of natural gas reserves in Alberta. Appendix C details the method used by the Board in estimating the long term requirements of the Province for annual and peak day volumes of gas. Methods of meeting Alberta's requirements are discussed in Appendix D. The deliverability characteristics of the fields were estimated from all available test data. Using the deliverability reserves relationships as shown graphically in the appendix, illustrated deliverability schedules were compiled. Table D-9, for example, shows one method in which the requirements of the Canadian Western Natural Gas Company Limited system could be met for the years 1953 to 1982 inclusive. In this manner the Board was able to determine which reserves were required for Alberta use and those which were surplus to provincial requirements.

(19) In Appendix L

In a similar manner deliverability schedules were developed to show how the requirements of the applicant could or could not be completely met from the remaining available reserves in the Province. This served as a basis for the Board's recommendation and is illustrated in Appendix F of the report.

CHAPTER XIII

TRANSPORTATION

Pipe lines that are subject to provincial jurisdiction are governed by the Pipe Line Act[20]. Broadly, this Act provides for

(1) the granting, upon application to the Minister of Mines and Minerals, of a permit for the construction of a pipe line;

(2) the acquisition by the permittee of such lands or interests therein as are necessary for the pipe line, under provisions administered by the Board of Public Utility Commissioners;

(3) a declaratory order of the Board of Public Utility Commissioners permitting the operation of the pipe line; and

(4) the authority of the Lieutenant Governor in Council to make regulations regarding pipe lines. (The regulations are administered by the Department of Mines and Minerals.)

A variety of provisions cover related matters, such as alteration and extensions of pipe lines or their routes, exemption from some provisions of the Act of gathering lines and service lines, penalties, etc.

For most purposes oil lines and gas lines are dealt with in the Act on the same basis. However, the Act pro-

(20) R.S.A. 1955, c.234

vides for a closer examination of an application for a permit for the construction in the case of a gas line, and the consideration in such a case of the financial responsibility of the applicant, any public interest that may be affected by the outcome of the application, and the needs and general good of the residents of the Province as a whole.

The function of the Oil and Gas Conservation Board under this Act is to advise the Minister on an application for a permit for the construction of the line. The Board receives a copy of the application and submissions in support of it, and may require further information of the applicant. The Board after consideration of the application notifies the Minister, in the case of a gas line, of its approval or disapproval and of any changes in the plan or details it deems expedient, and in the case of an oil line, of any objection it may have.

In the case of an application for an oil line permit, the Board's examination of the application and its report to the Minister are made from a technical point of view only.

Where an application for a gas line permit is received, the Board may, or may not, hold a public hearing with respect to it. It is the Board's practice to hold a hearing when applications may be in conflict, when there appear to be reasons why the applicant's plans may conflict with interests of other persons or when it appears desirable to extend the opportunity to make representations concerning the project, as in case of complexity or involving intangible factors.

Before a hearing, the Board requires the applicant to submit certain information which he will be expected to support at the hearing. This may include

(1) data respecting the geology and reserves of the field or area from which the line will take delivery;

(2) a production forecast showing a reasonable projection of yearly production rates and the derivation of the allocation factors on which the forecast is based;

(3) evidence of the suitability and acceptability of the gas to the proposed market;

(4) route maps and particulars of the terrain to be traversed;

(5) design material showing specifications, adequacy for foreseeable throughput, flexibility for increased throughput, economics of compressor horsepower related to line diameter, flow formula and characteristics of the fluid;

(6) particulars regarding capital investment, operating and other expense items, suggested rates and methods of financing.

The Board's concern in dealing with an application for a gas line permit is that the project be sound from an economic and engineering point of view considering the reserves, deliverability, design and markets, and that it is in the public interest.

A submission to your Commission dealing with other phases of the administration of the Pipe Line Act has been made by the Department of Mines and Minerals.

Some provisions of the Oil and Gas Conservation Act[21] also may affect a pipe line operation. Section 42 of that Act empowers the Board, with the approval of the Lieutenant Governor in Council, to declare the proprietor of a pipe line to be a common carrier. Under section 43, the Board, with the approval of the Lieutenant Governor in Council, may declare a person who purchases, produces or otherwise acquires oil or gas in a pool to be a common purchaser of oil or gas from the pool or pools designated by the Board. The Board, under section 46, may, after a hearing, order the owner or operator of a well, gas pipe line or processing plant to process, gather, deliver, buy or sell gas and construct the necessary facilities. An order under section 46 is subject to appeal to the Appellate Division of the Supreme Court of Alberta. In the event that agreement cannot be reached as to price to be paid for gas upon a purchase or sale ordered under section 46 or the charges to be paid for processing the gas, the Board of Public Utility Commissioners, on the application of any person interested, may determine the price or charges.

(21) Appendix A1

CHAPTER XIV

RESERVES OF OIL AND GAS AND TRENDS IN GROWTH OF RESERVES

There are two fundamentally different, but not completely independent methods for estimating the recoverable reserves of oil or gas in an underground reservoir. These are the volumetric and the material-balance methods. The volumetric method involves

(a) the estimation of the gross volume of the hydrocarbon containing reservoir through the determination of its areal extent and thickness,

(b) the calculation of the oil or gas contained in the reservoir through a knowledge of the rock porosity and the relative saturations of oil, gas or water,

(c) the estimation of the fraction of the oil or gas in the reservoir which may be recovered,

(d) the correction of the recoverable oil or gas volume to atmospheric or standard conditions of pressure and temperature, and

(e) in the case of gas, the deduction of appropriate processing and operating losses to give the "marketable" figure.

The material-balance method is an application of the law of conservation of mass to the fluids originally contained in the reservoir. It may be employed successfully only to reservoirs from which a significant amount of

measured production has been obtained and for which extensive pressure history is available. In many cases the calculation is mathematically quite complex, in others and especially in certain gas reservoirs, it may reduce to a simple graphical procedure involving a "pressure-decline" curve for the pool.

Estimation of Reservoir Volumes

The productive area of a reservoir is determined by geological studies, consisting of the correlation of logs, the identification of fluid interfaces and the preparation of structural contour maps. In some instances, access to seismic maps facilitates the construction of the structural contour maps. For a single well reserve, it is impossible to delineate the productive area accurately and judgment must be used.

The productive thicknesses and average porosities at wells within a reserve area are determined from both core analyses and logs, considered along with drill stem test and production data. Wherever possible, isopachous (equal-thickness) maps are prepared. The limiting isopach is drawn at the estimated areal limit of the reservoir. The interior isopachs are controlled by the productive thicknesses calculated for each well. The volume of the hydrocarbon containing reservoir rock is calculated from the isopachous map.

Reservoir Engineering Factors

Many factors related to the properties of the reservoir and its fluids and the reservoir pressure and temperature are important to the reserve estimate. The reservoir properties of porosity and fluid saturations are determined by interpretation of logs and by laboratory analysis of cores taken during the drilling of wells. The properties of the fluids including gas solubility in oil, oil gravity and compressibility, gas gravity and compressibility, and others are obtained by laboratory analysis of carefully collected fluid samples.

More difficult than any of the other factors to determine is the recovery factor. This must be estimated from a knowledge of the reservoir conditions, and in the case of oil especially, is extremely sensitive to the reservoir drive. Theoretical analyses, laboratory tests and the performance of similar reservoirs all aid in judging the recovery that may be expected.

Classification of Reserves

When an estimate is made by the volumetric method, the areal extent and often other factors must be determined with the aid of judgment. A rather common practice is to separate an estimate into two parts - the proven reserve and the probable reserve. The term proven generally is used with reference to that part of an area or reserve closely defined by productive wells and geological interpretation.

The area or reserve lying beyond this, less well defined but considered likely to contain oil or gas, is called probable. Every estimator has his own ideas on where to draw the difficult line between proven and probable.

A reserve determined by the material balance method usually is considered proven because it represents the quantity of oil or gas necessary to explain the pressure-production history of the reservoir.

The Board has adopted certain rather definite policies for its own use. For one well pools the Board usually assigns as proven, 500 to 1,100 acres to a gas reserve and one spacing unit, to an oil reserve. The Board also has accepted the principles and classifications used by the American Petroleum Institute and the Canadian Petroleum Association as they apply to oil reserves. The important points may be summarized as follows:

The reserve estimates for oil are made annually and refer solely to proven reserves and include only oil and condensate recoverable under existing economics and operating conditions. The proven reserves include both drilled and undrilled reserves. The proven drilled reserves, in any pool, include the oil estimated to be recoverable by the production systems now in operation and from the area actually drilled on the spacing pattern in effect in that pool. The proven undrilled reserves are those under undrilled spacing units which are so close and so related to the drilled units that there is every reasonable probability that they will produce when drilled.

The oil reserve estimates do not include

(a) oil under the unproven portions of developed fields;

(b) oil in untested prospects;

(c) oil that may be present in unknown prospects in regions believed to be generally favourable;

(d) oil that may become available by "secondary recovery" fluid injection methods from fields where such methods have not yet been applied and proven;

(e) oil that may become available from oil sands, oil shale, coal or other substitute sources.

In the case of new discoveries made during the year, the estimates of proven reserves in many cases necessarily represent only a fraction of the reserves which may ultimately be assigned to the new discoveries.

Reserves of condensate, recovered from the separators of gas and condensate wells, are included with those of oil but under separate classification. Condensate reserves are determined using the condensate to natural gas ratio applied to the estimate of recoverable natural gas ~~in place~~. The condensate to natural gas ratio is obtained from production tests on wells in the pool.

In the case of gas reserves the Board has found it convenient to define what it calls "established" reserves. These are the proven reserves plus a judgment portion of the probable reserves giving a total which may reasonably be depended upon. The portion of the probable figure may vary

from a small to fifty or more per cent depending upon circumstances. The Board believes its "established" gas reserve figures to be consistent as between pools and to be safe and conservative figures although not in all cases wholly proven.

Reserves of Oil and Condensate

A review of the growth in reserves of Alberta oil and condensate indicates that as of December 31st, 1957, the Province has net proven reserves of some 3.1 billion barrels. The distribution of the remaining recoverable reserves of oil and condensate by broad gravity ranges as of December 31st, 1957, is as follows:

Type	Millions of Barrels
Light and Medium Oils	2,893
Heavy Oil	34
Condensate	185
Total	3,112

The above figures represent the total of the estimates for all the individual pools in the Province. Each estimate is based on all available data on reservoir and production characteristics and refers to proven economically recoverable reserves.

With the addition of an estimated cumulative production of 812 million barrels, the total virgin reserves discovered to date amount to some 3.9 billion barrels. The increase in virgin recoverable reserves during 1957 was approximately 283 million barrels of which some 66 million barrels is

attributable to newly discovered pools. The net increase in recoverable reserves during 1957 is in excess of 146 million barrels.

Potential Production and Actual Production of Oil and Condensate

The maximum efficient rate of oil production for the Province based on a sound engineering appraisal of individual pools averaged some 756,000 barrels per day in 1957. This is an increase of 76,000 barels over the efficient rate for the previous year. The present production potential is estimated to be 787,000 barrels per day. When related to the actual 1957 production of 376,000 barrels per day, the average annual production potential exceeded production by some 380,000 barrels. The unproduced proportion of the production potential of the Province has increased from 30 per cent in 1954 to 50 per cent in 1957.

The details of the trends in the growth of the potential production and the actual production for the Province are contained in Appendix M.

Trends in Growth of Oil Reserves

When related to the 438 wildcat wells drilled in 1957 the 283 million barrels increase in virgin recoverable reserve of oil and condensate for the year indicates an average discovery rate of 646,000 barrels for each wildcat drilled. This may be compared to a discovery rate of 1,581,000 barrels per wildcat well in 1956. The 4,045 wildcats drilled to date when related to

the year-end cumulative virgin recoverable reserves indicate an average discovery ratio of some 970,000 barrels for each wildcat drilled. It is expected that on the average the discovery rate will remain near the present figure for some years and then will decline as the remaining undiscovered reserves decrease. Coupledwith estimates of the rate of drilling and the ultimate total wildcat wells these figures lead to an estimated ultimate oil reserve of some 15 billion barrels. This figure is on a virgin basis, i.e. includes all production. It is conservative in that it makes little allowance for increases in recovery which undoubtedly will accompany growth in "secondary recovery" methods.

Reserves of Gas

The Board has made several comprehensive studies of the gas reserves of the Province in conjunction with applications it has heard on gas export. The findings have been included in reports to the Lieutenant Governor in Council and in two special reports entitled "Natural Gas Reserves of the Province of Alberta and Other Related Data" dated November 1st, 1955, and January 31st, 1957. These appear in Appendix L. It is expected that a new summary of the Board's findings with respect to gas reserves will be published in connection with its recommendations to the Lieutenant Governor in Council at the conclusion of the current export hearings.

For present purposes, the Board staff has prepared a tabulation of its estimates of natural gas reserves as of December 31st, 1957. The estimate generally is consistent with previous ones but does not represent a finding of the Board with respect to the current gas export applications. Details of the estimate appear in Appendix I.

The staff estimate of established reserves for the Province as at December 31st, 1957, is some 21 trillion cubic feet. This represents an increase of about 2.7 trillion cubic feet since September 30th, 1956 - or a growth at the rate of 2.16 trillion cubic feet per year. The staff has classified its estimate as follows:

(1)	Reserves presently considered within economic reach	18.3 TCF
(2)	Reserves presently considered beyond economic reach	1.3 TCF
(3)	Reserves subject to lengthy deferment due to production of oil or due to reinjection	1.4 TCF
	Total Reserves	21.0 TCF

Reserves of Natural Gas Liquids

A breakdown of the total gas reserve figure by categories of gas related to the content of recoverable liquids appears with details of the recoverable reserves of propane, butane and natural gasoline in Appendix J. The total esti-

mated reserves of these liquids recoverable from the 21.3 trillion cubic feet of gas reserves are

	Millions of Gallons
Propane	5,090
Butanes	4,800
Pentanes plus	5,660
Total	15,550

Trends in Growth of Gas Reserves

The recent increase in gas reserves at the rate of 2.16 trillion cubic feet per year may be related to the 438 wildcat wells drilled during 1957. The actual gas reserve growth per wildcat well drilled is just under 5 billion cubic feet. When it is recognized that the 1957 discoveries are not yet nearly fully evaluated this figure confirms the conservatism of the Board's previously reported opinion[22] that the Province can safely anticipate a growth rate of 6 billion cubic feet per wildcat well for the next several years. Such a growth rate, coupled with an estimate of the rate of drilling and the ultimate total wildcat wells leads to an estimated ultimate gas reserve of 60 to 80 trillion cubic feet. This figure is on a virgin basis, i.e. includes all production.

D. Hume and C.P.A witnesses agree with this para substantially

Further details of the trends in growth of gas reserves appear in Appendix M.

(22) in Appendix L

CHAPTER XV

RECORDS AND STATISTICS

The Board keeps records and statistics on all aspects of the licensing, drilling and production activity for all wells drilled in the Province. The well name register, the well history and completion records, the well production records, together with pipe line, transporter, purchaser, oil refinery and gas plant records, form the basis of many secondary records and statistics on the geological, engineering and marketing phases of the oil and gas industry in the Province.

The geological classification of wells, described in Appendix O, is a useful tool in statistical analyses.

Figure XV-1 presents in chart form these records and statistics and indicates the broad relationship that exists between the primary records and the various supplementary records, statistics, studies and publications of the Board.

A brief description of the records and statistics kept by the Board is presented herewith:

1. Primary Records

(1) Well Name Register

A record of official well names indicating licence number, location, name of licensee, name of his agent and name of drilling contractor.

(2) Well History and Completion Records

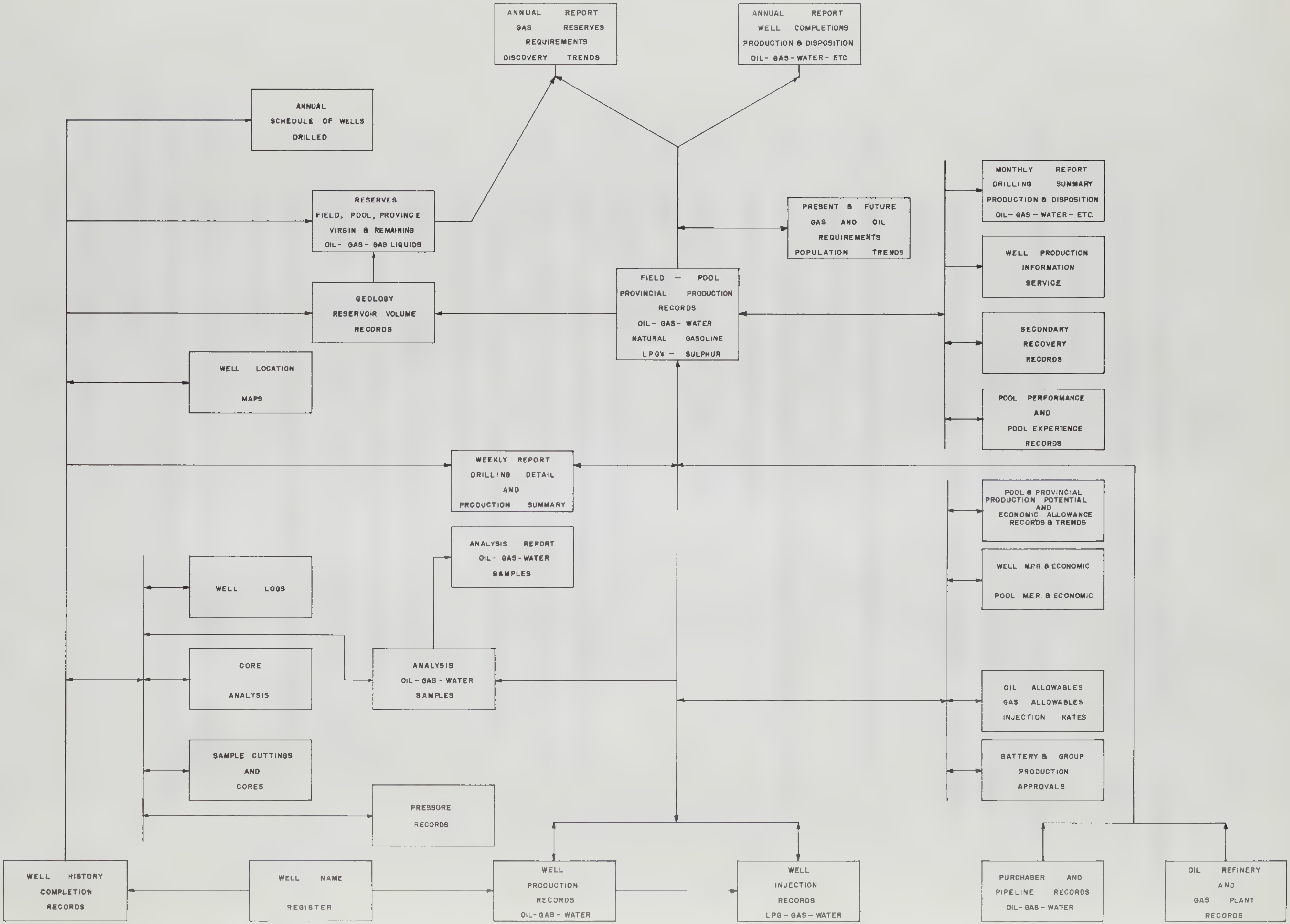
A record for each well showing

(a) well name, licence number, location,

FIGURE XV — I

OIL AND GAS CONSERVATION BOARD

RECORDS AND STATISTICS



classification, licensee, agent and drilling contractor;

(b) elevation ground, Kelly Bushing elevation and commenced drilling date;

(c) surface casing details, deviation surveys, cored intervals, drill stem test intervals and results, finished drilling date, total depth, perforations and treatments;

(d) production casing details, abandonment details or first production details;

(e) Board geological markers, successful zone or zones and well completion status;

(f) sample cuttings and cores;

(g) well logs.

(3) Well Production and Injection Records

A record for each producing or operated well showing

(a) well name, location, date of first production or injection, mineral ownership, producing pool, field and operating status;

(b) monthly, annual and cumulative production or injection or oil, water and gas liquids;

(c) monthly and cumulative overproduction or under-production status with respect to production allowables;

(d) gas-oil and water-oil ratios and penalty factors;

(e) disposition details of produced oil, gas and water.

(4) Pressure Records

(a) virgin pool pressures;

(b) pool pressure surveys;

(c) back pressure tests;

(d) productivity indices.

(5) Purchaser and Pipe Line Records

A record for each purchaser or transporter of oil, gas, water or natural gas liquids showing the source and disposition of all oil, gas, water or natural gas liquids purchased or received.

(6) Oil Refinery and Gas Plant Records

A record for each oil refinery and gas plant showing the receipts and source of oil, gas or other materials and the products recovered from such receipts.

2. Secondary Records

Secondary records, in most instances, are established from data contained in the primary records and represent data condensed into a usable form.

These records may be subdivided into two broad groups, namely, geological, engineering or statistical records and interpretative and administrative records.

(1) Geological, Engineering and Statistical Records

(a) core analyses;

(b) oil, gas, water analyses;

(c) well location maps;

(d) field, pool, provincial production records;

(e) secondary recovery records;

(f) oil and gas allowables and injection rates;

(g) pool performances and pool experience records.

(2) Interpretative and Administrative Records

(a) battery and group production approvals;

(b) well and pool MPR and MER;

(c) well and pool economic allowance;

(d) pool and provincial production potential and economic allowance and trends;

(e) geology reservoir volume records;

(f) field, pool, Province, virgin and remaining reserves and discovery trends;

(g) present and future gas and oil requirements and population trends.

The records, statistics and certain of the interpretative data described above form the basis of the various services and publications described in Appendix K.

In addition special studies have been carried out on reserves and requirements. The results of some of these studies are included in the Board's submission to the Royal Commission on Canada's Economic Prospects[23]. More recent studies dealing with reserves and discovery trends are included in Appendix M.

(23) Appendix N

CHAPTER XVI

PROCEDURE OF THE BOARD

As may be surmised in perusing the Oil and Gas Conservation Act and the regulations thereunder, the Board in its functioning issues numerous orders and directions. Some of the orders, namely, proration orders and compulsory pooling or unit operation orders require the approval of the Lieutenant Governor in Council. Orders of a "legislative nature" are filed under the Regulations Act [24].

In most cases the Board holds a hearing before making an order or direction, but unless the regulations specifically require a hearing, the rule may be varied. However, the Board holds a hearing whenever it appears that there may be some interest other than that of the applicant that may be affected or where for some other reason the Board considers a hearing desirable. For example, the Board might not have a hearing before making an order limiting pit disposal of water as such an order would simply specify how good production practices were maintained. But on the other hand, when the Board makes an order establishing, in a field or area, a spacing unit different from that prescribed in the regulations, it first holds a hearing, as a variation from standard conservation rules is involved.

In cases that it considers suitable, the Board may appoint examiners to conduct a hearing, but in such a case

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(24) Statutes of Alberta, 1957 c. 78;

an interested person has the right to ask the Board to conduct the hearing. Where examiners are appointed they usually conduct the whole of the hearing rather than some separate phases of it.

The Board endeavours to give sufficient notice of a hearing to enable each interested person to know what will be dealt with and to prepare any submission he may wish to make, and at the hearing gives each party the opportunity to present whatever he wishes to say and to hear whatever the other interested parties wish to submit.

The Board in the conduct of its hearing is not bound by legal rules of evidence. As a result, some evidence that would not be acceptable in a court is heard by the Board and this is considerable advantage where much of the evidence to be considered is in a nature of opinion evidence of experts. If a proposed witness fails to comply with a notice by the Board to attend, the Board may apply to a judge of the Supreme Court of Alberta for the issue of a bench warrant.

In addition to its "formal" hearings, the Board upon occasion may meet with operators to discuss the formulation of a policy or the development of a situation that may lead to a Board order or a direction. Thus, if the Board felt that a point was being approached where pressure maintenance in a pool was desirable its first step would be to discuss the matter with the operators in the pool. This would give the operators an opportunity of considering the matter if they

had not already done so and of formulating a voluntary program if they agreed that the pressure maintenance was desirable.

A provision is made in the Act for rehearings and appeals. Under section 118, a person affected by a Board order may apply for a rehearing within 45 days. Section 119 provides for appeals to the Appellate Division of the Supreme Court of Alberta. An appeal on the question of jurisdiction may be taken from any order made under Part IV or Part V of the Oil and Gas Conservation Act. These Parts deal with drilling, production, transportation and disposition of oil or gas, and the right to appeal on the question of jurisdiction affects most orders. In addition, an appeal from an order under section 37 or 46 may be made to the Appellate Division on the basis that there was insufficient evidence or that the order was wrongly made.

There is one type of Board order that is subject to a procedure entirely different from the others due to its emergency nature, and that is an order under section 123 closing an area to travel where hazardous conditions exist, such as those that arise in a case of a well flowing uncontrolled.

The procedures and procedural powers provided for in the Oil and Gas Conservation Act are applicable to hearings by the Board under other Acts.

Orders of the Board, when issued, are numbered and the number is prefixed by a symbol indicating the type of order.

This may assist in a classification on the following basis:

1. Approved by Order in Council and filed under Regulations Act:

   P orders - compulsory pooling

   Compulsory unit operations orders (if and when)

   Common carrier and common purchaser orders

2. Approved by Order in Council and not filed under Regulations Act:

   MD orders - oil prorationing

   MDS orders - transfer of allowable of wells capable of oil production but used for conservation purposes.

   Permits under Gas Resources Preservation Act, 1956.

3. Not approved by Order in Council but filed under Regulations Act:

   F orders - designating fields

   G orders - designating pools

   SU orders - prescribing spacing units other than normal

   W orders - restricting surface disposal of water in fields or areas

   GC orders- requiring gathering, processing and either marketing or storage of gas

   Misc orders - requiring pressure maintenance or the like in a field or pool

   Orders under section 46 requiring purchase, sale, transportation, processing, etc. of gas.

4. Not approved by Order in Council and not filed under Regulations Act:

C orders - closing in a well

FH orders - closing hazardous area to travel, under section 123

GA orders - gas allowables

LL orders - gas allowables in Lloydminster Field

MH orders - gas allowables in Medicine Hat Field

TV orders - gas allowables in Turner Valley Field

Misc orders - orders (other than C orders) made upon infractions of Act or regulations, orders relieving from off-target penalties, etc.

Permits under section 45 authorizing use or consumption of gas

Approval of schemes under section 38 or of agreements for unit operations.

STAFF ESTIMATE OF GAS RESERVES

DECEMBER 31, 1957

The Board has published estimates of the natural gas reserves of the Province of Alberta on six occasions commencing with its first Report to the Lieutanant Governor in Council in 1951. An up to date summary of the Board's findings with respect to established reserves will be published atthe conclusion of the hearings of the present applications for permits to remove gas from the Province. In the meantime, the Board staff has prepared a tabulation of its estimates of natural gas reserves as of January 1st, 1958. It estimates that the present total reserves of natural gas are 21.0 trillion cubic feet, an increase of 2.7 trillion cubic feet over those estimated in the Board's January, 1957, report.

An examination of the reserves shows that about 55 per cent of the 2.7 trillion cubic feet increase is attributable to new discoveries and the balance to a net increase of previously known reserves. The discovery of the Pine Creek and Waterton reserves account for over half of the increase due to new discoveries. Increases due to adjustments of previously known reserves were greatest at Bindloss, Calgary, Carbon, Medicine Hat, Savanna Creek and Westerose South fields. These were partially offset by downward revision in reserves at Harmattan-Elkton, Pembina, Pincher Creek and Windfall.

The total disposable natural gas reserves of 21 trillion

cubic feet may be classified as follows:

(1)	Reserves presently considered within economic reach	18.3 TCF
(2)	Reserves presently considered beyond economic reach	1.3 TCF
(3)	Reserves subject to lengthy deferment due to production of oil or due to reinjection	1.4 TCF
	Total Reserves	21.0 TCF

In Table I-1 are individually listed all reserves estimated by the Board staff to be 10 Bcf or greater, plus, some smaller reserves of special interest. At the end of the table are summarized the reserves of 46 small areas whose individual reserves are less than 10 Bcf and which are considered to be within economic reach and those of 136 small areas which are presently considered to be beyond economic reach.

A brief description of Table I-1 is as follows:

Column	Presents
1.	Name of field or area
2.	Geological formation or zone from which gas is obtained. The Stratigraphic relationship of the formations is shown in Figure III-2.
3.	Estimated original gas in place expressed in billions of cubic feet at standard conditions.
4.	Discount to be applied to original gas in place (Column 3) to account for the gas left in the reservoir at abandonment.

Column	Presents
5.	Discount to be applied, after that for reservoir loss, to account for surface loss. This factor includes (where applicable) allowance for gas flared, operational loss, field and/or plant fuel, and processing shrinkage attending the removal of carbon dioxide, hydrogen sulphide, propane and butanes plus.
6.	Estimated disposable gas reserves as at January 1st, 1958, expressed in billions of cubic feet at standard conditions.
7.	Comments of specific application to individual fields.

TABLE I-1

OIL AND GAS CONSERVATION BOARD

ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA, JANUARY 1, 1958.(3)

1 FIELD OR AREA	2 ZONE (5)	3 ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	4 DISCOUNT FOR RESERVOIR LOSS PER CENT	5 DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	6 DISPOSABLE GAS(3) BILLIONS OF CUBIC FEET	7 REMARKS
Acheson	Viking	13.4(i) 13.2(ii)	20	5	10	(i) Original (ii) Less 0.2 Bcf produced to December 31, 1957.
	Blairmore Solution	73.5(i) 72.9(ii)	25	10	49	Reserves adjusted by 1.1 factor to convert to 1000 BTU basis. (i) Original (ii) Less 0.6 Bcf produced to December 31, 1957.
	Leduc (D-3) Solution	90.3(i) 82.9(ii)	45	25	31.6	Reserves adjusted by 1.2 factor to convert to 1000 BTU basis. (i) Original (ii) Less 7.4 Bcf produced to December 31, 1957.
Alexander	Basal Blairmore	52.6(i) 44.7(ii)	15	5	35	(i) Original (ii) Less 7.9 Bcf produced to December 31, 1957.
Alhambra	Belly River Solution	3.2	35	5	2	
	Cardium Non-Associated	13.2	20	5	10	
	Cardium Solution	26.6(i) 26.0(ii)	35	10	15	(i) Original (ii) Less 0.6 Bcf produced to December 31, 1957.
Athabasca	Lower Cretaceous	4.9(i) 4.1(ii)	15	5	3.2	Supplies local utility. (i) Original (ii) Less 0.8 Bcf produced to December 31, 1957.
Athabasca East	Wabamun (D-1)	2.3(i) 1.9(ii)	10	5	1.6	Supplies local utility. (i) Original (ii) Less 0.4 Bcf produced to December 31, 1957.
Atlee Buffalo	Viking	98.3	25	5	70	
	Basal Blairmore	92.2	20	5	70	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC.,(4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
BEAVER CREEK	WABAMUN	26.2	10	15	20	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
BEAVERHILL LAKE	VIKING	118.8(I) 118.6(II)	20	5	90	SUPPLIES LOCAL UTILITY SYSTEM. (I) ORIGINAL (II) LESS 0.2 BCF PRODUCED TO DECEMBER 31, 1957.
	BLAIRMORE	3.9	20	5	3	
BELLOY	CADOTTE	5.3	20	5	4	
	NOTIKEWIN	9.2	20	5	7	
	GETHING	62.0	15	5	50	
	MISSISSIPPIAN	17.5	10	5	15	
BELLSHILL LAKE	VIKING	4.2	25	5	3	
	BLAIRMORE NON-ASSOCIATED	88.0(I) 87.8(II)	10	5	75	(I) ORIGINAL (II) LESS 0.2 BCF PRODUCED TO DECEMBER 31, 1957.
	BLAIRMORE ASSOCIATED	2.6	15	10	2	
	BLAIRMORE SOLUTION	37.0	40	10	20	
BINDLOSS	VIKING	348.0(I) 346.7(II)	15	5	280	EXPORTING TO EASTERN CANADA. (I) ORIGINAL (II) LESS 1.3 BCF PRODUCED TO DECEMBER 31, 1957.
	BASAL BLAIRMORE	23.4	10	5	20	
BITTERN LAKE	VIKING	1.4	25	5	1	
	BLAIRMORE	29.3	10	5	25	
BLACK BUTTE	BOW ISLAND	14.0	10	5	12	
	JURASSIC	23.3(I) 13.9(II)	20	5	8.7	EXPORTING TO MONTANA. (I) ORIGINAL (II) LESS 9.4 BCF PRODUCED TO DECEMBER 31, 1957.
	MISSISSIPPIAN	12.4	15	5	10	
BLUERIDGE	DETRITAL	14.1	10	5	12	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	MISSISSIPPIAN	1.3	20	5	1	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Bonnie Glen	Leduc Associated	488.7(i) 487.0(ii)	10	15	372	Adjusted by 1.23 factor to convert to 1000 BTU basis. (i) Original (ii) Plus 1.7 Bcf injected to December 31, 1957.
	Leduc Solution	686.0(i) 649.1(ii)	40	25	281	Adjust by 1.23 factor to convert to 1000 BTU basis. (i) Original (ii) Less 36.9 produced to December 31, 1957.
Bonnyville	Colony	4.0(i) 3.2(ii)	15	5	2.5	Supplies Local Utility. (i) Original (ii) Less 0.8 produced to December 31, 1957.
Bow Island	Bow Island	21.0	20	5	16	Used as a storage reservoir by CWNG.
Boyle-Mustang-Amisk Lake	Blairmore	7.0	25	5	5	Presently considered beyond economic reach.
	Nisku	19.8	20	5	15	
Braeburn	Cadomin	26.3	20	5	20	
	Triassic	6.6	20	5	5	
	Permo-Penn	58.5	10	5	50	
Braeburn West	Peace River	46.8	10	5	40	
	Cadomin	5.8	10	5	5	
	Jurassic	3.9	15	10	3	
	Triassic	13.2	20	5	10	
Brooks-Northeast	Bow Island	5.7	15	5	5	Possible Local Utility Supply.
	Sunburst	6.3(i) 5.0(ii)	10	5	4.2	Supplies Local Utility. (i) Original (ii) Less 1.3 produced to December 31, 1957.
Brooks-Tilley	Milk River	28.5(i) 25.7(ii)	20	5	19	Supplies Local Utility. (i) Original (ii) Less 2.8 Bcf produced to December 31, 1957.
	Sunburst	12.4	15	5	10	Possible local utility Supply

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Burnt River	Paddy	2.3	10	5	2	
	Bluesky	9.4	10	5	8	
Calahoo	Basal Blairmore	16.1	15	5	13	
Calgary	Basal Quartz	9.9	15	5	8	
	Elkton	69.4	10	20	50	
	Wabamun	903	10	60(i)	325	(i) High acid gas content. Note: Includes Kathryn Area.
Campbell-Namao	Basal Blairmore	60.8(i) 59.2(ii)	15	20(iii)	40	(i) Original (ii) 1.8 Bcf produced to December 31, 1957. Injected 0.2 Bcf to December 31, 1957. Net production 1.6 Bcf. (iii) Requires processing with some gas gathering difficulties.
Carbon	Viking	3.9	20	5	3	
	Blairmore	233.9	10	5	200	
Carson Creek	Beaverhill Lake	39.2	10	15	30	
Castor	Viking	22.3	15	5	18	Possible local utility supply.
	Blairmore	2.3	10	5	2	
Cessford	Viking	98.7	20	5	75	
	Basal Colorado	1020.0	20	5	775	
	Basal Colorado Solution	8.4(i) 7.4(ii)	35	10	4	Solution gas reserves presently considered beyond economic reach. (i) Original (ii) Less 1.0 Bcf produced to December 31, 1957.
	Basal Blairmore	272.4	15	5	220	
	Basal Blairmore Solution	63.4	35	15	35	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC.,(4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
CHIGWELL	BLAIRMORE	30.9	10	10	25	
CHINOOK	PADDY	7.0	20	10	5	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	CADOTTE	24.7	10	10	20	
	NOTIKEWIN	24.7	10	10	20	
CHISHOLM	BLAIRMORE	11.7	10	5	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
CLIVE	VIKING	3.9	20	5	3	
	BLAIRMORE	3.7	15	5	3	
	NISKU ASSOCIATED	9.2	10	15	7	
	LEDUC ASSOCIATED	4.7	15	25	3	
COLD LAKE	COLONY	5.1(I) 3.8(II)	25	5	2.4	SUPPLIES LOCAL UTILITY. (I) ORIGINAL (II) LESS 1.3 BCF PRODUCED TO DECEMBER 31, 1957.
COMREY	BOW ISLAND	52.8(I) 52.7(II)	10	5	45	EXPORTING TO MONTANA. (I) ORIGINAL (II) LESS 0.1 BCF PRODUCED TO DECEMBER 31, 1957.
CONNORSVILLE	VIKING	8.7	15	5	7	
	BASAL BLAIRMORE	14.5	20	5	11	
CONTROL	VIKING	11.7	10	5	10	
	BASAL BLAIRMORE	11.7	10	5	10	
COUNTESS	BOW ISLAND	65.8	20	5	50	
	BASAL BLAIRMORE	5.0	15	5	4	
CROSSFIELD	MISSISSIPPIAN	208.2	10	20	150	
DIXONVILLE	GETHING	31.6	10	5	27	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
DONALDA	VIKING	12.4	15	5	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	DETRITAL	2.3	10	5	2	

1 FIELD OR AREA	2 ZONE (5)	3 ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	4 DISCOUNT FOR RESERVOIR LOSS PER CENT	5 DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	6 DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	7 REMARKS
DOWLING LAKE	DETRITAL	1.0(I) 0.7(II)	20	5	0.5	SUPPLIES LOCAL UTILITY. (I) ORIGINAL (II) LESS 0.3 BCF PRODUCED TO DECEMBER 31, 1957.
	BOW ISLAND	13.2	20	5	10	
	BASAL COLORADO	11.8	20	5	9	
DUHAMEL	VIKING	4.8(I) 4.7(II)	10	5	4	(I) ORIGINAL (2) LESS 0.1 BCF PRODUCED TO DECEMBER 31, 1957.
	BLAIRMORE	2.3	10	5	2	
	NISKU ASSOCIATED	2.5	10	10	2	
	DEVONIAN SOLUTION	10.2(I) 9.1(II)	40	20	4	(I) ORIGINAL (II) 1.2 BCF PRODUCED TO DECEMBER 31, 1957. INJECTED 0.1 BCF TO DECEMBER 31, 1957. NET PRODUCTION 1.1 BCF. VIKING AND DEVONIAN GAS BEING INJECTED INTO D-3.
DUVERNAY	VIKING	1.5 (I) 0.6(II)	20	5	0.3	SUPPLIES CHEMICAL PLANT. (I) ORIGINAL (II) LESS 0.9 BCF PRODUCED TO TO DECEMBER 31, 1957.
DYBERG	BASAL BELLY RIVER	3.5	10	5	3	
	VIKING	9.4	10	5	8	
	BASAL BLAIRMORE	3.7	15	5	3	
EAGLE HILL	MISSISSIPPIAN ASSOCIATED	39.2	10	15	30	
EAGLESHAM	PEACE RIVER	1.4	25	5	1	
	GETHING	5.0	15	5	4	
	CADOMIN	4.7	10	5	4	
	MISSISSIPPIAN	9.2	20	5	7	
ELK POINT	BLAIRMORE	1.2(I) 0.8(II)	25	5	0.5	SUPPLIES LOCAL UTILITY. (I) ORIGINAL (II) LESS 0.4 BCF PRODUCED TO DECEMBER 31, 1957.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
ENCHANT	BOW ISLAND	7.0	25	5	5	
	ELLIS	2.6	20	5	2	
	DETRITAL	1.3	20	5	1	
	RUNDLE	3.9	20	5	3	
ERSKINE	VIKING	4.2	25	5	3	
	BLAIRMORE	20.2(I) 19.8(II)	15	10	15	(I) ORIGINAL (II) LESS 0.4 BCF PRODUCED TO DECEMBER 31, 1957.
	LEDUC ASSOCIATED	30.6	10	20	22	
	LEDUC SOLUTION	17.7(I) 16.2(II)	35	20	8	(I) ORIGINAL (II) LESS 1.5 BCF PRODUCED TO DECEMBER 31, 1957.
ETZIKOM	BOW ISLAND	177.7(I) 174.1(II)	15	5	140	SUPPLIES FERTILIZER PLANT AT MEDICINE HAT AND THE CITY OF MEDICINE HAT. (I) ORIGINAL (II) LESS 3.6 PRODUCED TO DECEMBER 31, 1957.
	BASAL BLAIRMORE	1.4	25	5	1	
EXCELSIOR	VIKING	8.7	15	5	7	
	BASAL BLAIRMORE NON-ASSOCIATED	14.0	10	5	12	
	BASAL BLAIRMORE ASSOCIATED	38.6	10	5	33	
	BASAL BLAIRMORE SOLUTION	5.5	15	15	4	BASAL BLAIRMORE SOLUTION GAS PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
EYREMORE	BOW ISLAND	18.1	30(I)	5	12	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH. (I) HIGH RESERVOIR LOSS DUE TO LOW DELIVERABILITY.
FAIRYDELL-BON ACCORD	VIKING	97.1(I) 93.0(II)	20	5	70	(I) ORIGINAL (II) LESS 4.1 BCF PRODUCED TO DECEMBER 31, 1957.
	BASAL BLAIRMORE	7.2	10	5	6	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Faust South	Gething	11.7	10	5	10	Presently considered beyond economic reach.
Fenn-Big Valley	Viking	18.6	15	5	15	
	Nisku Solution	185.4(i) 172.7(ii)	35	35	70	(i) Original (ii) Less 12.7 Bcf produced to December 31, 1957.
	Leduc	12.0(i) 11.3(ii)	35	30	5	(i) Original (ii) Less 0.7 Bcf produced to December 31, 1957.
Foremost	Bow Island	34.9(i) 29.1(ii)	20	5	21	(i) Original (ii) Less 5.8 Bcf produced to December 31, 1957.
Fort Saskatchewan	Viking	162.0(i) 142.4(ii)	10	5	120	(i) Original (ii) Less 19.6 Bcf produced to December 31, 1957.
Garrington	Viking	18.5	10	10	15	
	Leduc	30.8	10	10	25	
Gem	Viking	10.5	20	5	8	
	Basal Colorado	1.4	25	5	1	
	Basal Blairmore	2.6	20	5	2	
Ghost Pine	Blairmore	16.1	10	10	13	
	Rundle	2.6	15	10	2	
Gilby	Viking Non-Associated	4.1	20	10	3	
	Basal Blairmore	10.4	15	10	8	
	Mississippian	235.3	10	15	180	
	Wabamun	6.9	10	20	5	
Glen Park	Blairmore Non-Associated	4.7	10	5	4	
	Blairmore Associated	4.6(i) 4.1(ii)	20	5	3	(i) Original (ii) Less 0.5 Bcf produced to December 31, 1957.
	Leduc Solution	17.7(i) 16.5(ii)	40	15	8	(i) Original (ii) Less 1.2 Bcf produced to December 31, 1957.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Golden Spike	Viking	4.5 (i) 3.0(ii)	20	5	2	(i) Original (ii) Less 1.5 Bcf produced to December 31, 1957.
	Basal Blairmore	10.9(i) 10.0(ii)	15	5	8	(i) Original (ii) Less 0.9 Bcf produced to December 31, 1957.
	Wabamun	15.3(i) 13.3(ii)	10	15	10	(i) Original (ii) Less 2.0 Bcf produced to December 31, 1957.
	Nisku Associated	3.9	10	15	3	
	Nisku Solution	12.3 (i) 11.8(ii)	35	20	6	(i) Original (ii) Less 0.5 Bcf produced to December 31, 1957.
	Leduc Solution	118.9(i) 124.5(ii)	25	25	70	(i) Original (ii) 6.4 Bcf produced to December 31, 1957. Stored 12.0 Bcf to December 31, 1957 Net production - 5.6 Bcf.
Goodwin Lake	Viking	5.3	20	5	4	
	Nordegg	30.9	10	10	25	
Gordondale	Cadotte	46.8	10	5	40	Exporting to British Columbia and United States.
	Gething	11.7	10	5	10	
	Cadomin	81.9	10	5	70	
Grassy Island Lake	Viking	28.1	25	5	20	
Hackett	Basal Blairmore	52.6	10	5	45	
Hairy Hill	Viking	2.8	25	5	2	
	Blairmore	14.8(i) 13.4(ii)	20	5	10	(i) Original (ii) Less 1.3 Bcf produced to December 31, 1957. Supplies Chemical plant.
Hamelin Creek	Cadotte	7.0	25	5	5	
	Gething	3.7	15	5	3	
	Cadomin	35.1	10	5	30	
	Triassic	1.4	25	5	1	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
HAMILTON LAKE	VIKING	53.3 (I) 52.8(II)	20	5	40	(I) ORIGINAL (II) LESS 0.5 BCF PRODUCED TO DECEMBER 31, 1957.
HARMATTAN-ELKTON	MISSISSIPPIAN NON-ASSOCIATED	* 76.5	10	20	55	
	MISSISSIPPIAN ASSOCIATED	1082.5	10	20	780	
	MISSISSIPPIAN SOLUTION	179.5(I) 176.0(II)	35	25	85	(I) ORIGINAL (II) LESS 3.5 BCF PRODUCED TO DECEMBER 31, 1957.
HERCULES	VIKING	11.8	20	5	9	
	BLAIRMORE	13.2	20	5	10	
HILDA	MEDICINE HAT	21.1	25	5	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
HOLBORNE	CARDIUM	8.4	25	5	6	
	BASAL BLAIRMORE	23.5	15	10	18	
HOMEGLEN-RIMBEY	LEDUC ASSOCIATED	1013.0	10	20	730	
	LEDUC SOLUTION	96.2(I) 91.9(II)	40	25	40	(I) ORIGINAL (II) LESS 4.3 BCF PRODUCED TO DECEMBER 31, 1957.
HUSSAR	VIKING	5.3	20	5	4	
	BASAL COLORADO	42.1	25	5	30	NOTE: MAKEPEACE AND CHANCELLOR INCLUDED.
	BLAIRMORE	187.2	10	5	160	
INNISFAIL	WABAMUN	3.9	15	10	3	
	LEDUC ASSOCIATED	5.1	10	35	3	
	LEDUC SOLUTION	103.0(I) 102.7(II)	40	35	40	(I) ORIGINAL (II) LESS 0.3 BCF PRODUCED TO DECEMBER 31, 1957.
JOARCAM	VIKING ASSOCIATED	65.7	20	5	50	DEFERRED UNTIL OIL RESERVE DEPLETED.
	VIKING SOLUTION	51.9 (I) 38.4(II)	40	15	15	(I) ORIGINAL (II) LESS 13.5 BCF PRODUCED TO DECEMBER 31, 1957. PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
JOFFRE	VIKING SOLUTION	35.3(I) 28.2(II)	40	15	12	(I) ORIGINAL (II) LESS 7.1 BCF PRODUCED TO DECEMBER 31, 1957. PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	NISKU SOLUTION	23.1(I) 23.0(II)	40	20	11	(I) ORIGINAL (II) LESS 0.1 BCF PRODUCED TO DECEMBER 31, 1957.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Jumping Pound	Rundle	788.5(i) 703.2(ii)	10	17	518	(i) Original (ii) Less 85.3 Bcf produced to December 31, 1957.
Kessler	Viking	70.2	25	5	50	
Kevisville	Leduc	18.5	10	40(i)	10	(i) High H_2S and heavy ends. Will require processing. Presently considered beyond economic reach.
Keystone	Basal Belly River	35.1	10	5	30	Presently considered beyond economic reach.
	Cardium Solution	72.2(i) 72.0(ii)	35	25	35	(i) Original (ii) Less 0.2 Bcf produced to December 31, 1957.
Lac La Biche	Viking	46.1	20	5	35	Presently considered beyond economic reach.
	Blairmore	12.4	15	5	10	
Lambert Creek	Wabamun	39.5	10	10	32	Presently considered beyond Economic reach.
Leafland	Cardium Solution	20.7(i) 20.6(ii)	35	25	10	Presently considered beyond Economic reach. (i) Original (ii) Less 0.1 Bcf produced to December 31, 1957.
Leahurst	Basal Blairmore	9.8 (i) 9.3(ii)	15	5	7.4	Supplies local utility. (i) Original (ii) Less 0.5 Bcf produced to December 31, 1957.
Leduc-Woodbend	Viking	16.5(i) 15.9(ii)	20	5	12	(i) Original (ii) Less 0.6 Bcf produced to December 31, 1957.
	Blairmore	225.8(i) 223.4(ii)	25	10	150	14 Bcf considered beyond economic reach. (i) Original (ii) Less 2.4 Bcf produced to December 31, 1957.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Leduc-Woodbend (cont)	Nisku Associated	42.5	10	15	32.5	
	Nisku Solution	152.0(i) 110.9 (ii)	25	30	51	(i) Original (ii) Less 41.1 Bcf produced to December 31, 1957.
	Leduc Associated	521.0(i) 487.6(ii)	15	15	348	(i) Original (ii) Less 33.4 Bcf produced to December 31, 1957.
	Leduc Solution	221.0(i) 152.6(ii)	40	30	45	(i) Original (ii) Less 68.4 Bcf produced to December 31, 1957. Blairmore, Nisku, and Leduc all adjusted by 1.16 factor to convert to 1000 BTU basis.
Lindbergh	Viking	3.2	35	5	2	
	Colony	4.1 (i) 1.9(ii)	20	5	1.0	Supplies salt plant. (i) Original (ii) Less 2.2 Bcf produced to December 31, 1957.
Little Smoky	Permo-Penn	2.5	15	5	2	Presently considered beyond economic reach.
	Mississippian	2.5	15	5	2	
	Devonian Associated and Solution	22.5(i) 22.2(ii)	35	30	10	(i) Original (ii) Less 0.3 Bcf produced to December 31, 1957.
Lloydminster	Colony	6.7	40	15	3.4	Supplies local utility.
	Sparky	7.5	60	40	1.8	A total of 12.7 Bcf has been produced to December 31, 1957 from both zones.
Lovett	Rundle	91.5	10	15	70	Presently considered beyond economic reach.
Majeau Lake	Blairmore	2.6	20	5	2	Presently considered beyond economic reach.
	Mississippian	11.7	10	5	10	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Malmo	Viking	6.2	15	5	5	
	Basal Blairmore	9.0(i) 8.6(ii)	30	15	5	(i) Original (ii) Less 0.4 Bcf produced to December 31, 1957.
	Devonian Associated and Solution	16.9(i) 15.1(ii)	30	20	8	(i) Original (ii) Less 1.8 Bcf produced to December 31, 1957.
Manyberries	Bow Island	66.8(i) 63.4(ii)	20	5	45	(i) Original (ii) Less 3.4 Bcf produced to December 31, 1957.
Mazeppa	Mississippian	19.6	10	15	15	
Medicine Hat	Medicine Hat	1990.6(i) 1788.4(ii)	20	6.5	1300	(i) Original (ii) Less 202.2 Bcf produced to December 31, 1957.
	Bow Island	19.7	20	5	15	
	Ellis	6.2	15	5	5	
Millet	Lower Cretaceous	20.8	20	10	15	Presently considered beyond economic reach.
Minnehik-Buck Lake	Basal Blairmore	2.8	25	5	2	
	Mississippian (Pekisko)	130.7	10	15	100	
Morinville	Viking	2.8	25	5	2	
	Basal Blairmore	126.0(i) 108.3(ii)	15	5	85	(i) Original (ii) Less 17.7 Bcf produced to December 31, 1957.
Mountain Park	Triassic	29.2	10	5	25	Presently considered beyond economic reach.
Nevis	Blairmore	65.8	20	5	50	
	Devonian	695.0	10	20(i)	500	(i) High acid gas content.
New Norway	Viking	2.5	20	5	2	
	Basal Blairmore	9.4	10	5	8	
	Devonian	7.7(i) 6.7(ii)	35	25	3	(i) Original (ii) Less 1.0 Bcf produced to December 31, 1957.

1	2	3	4	5	6	7
Field or Area	Zone (5)	Estimated Original Gas in Place Billions of Cubic Feet	Discount for Reservoir Loss Per Cent	Discount for Surface Loss, etc., (4) Per Cent	Disposable Gas (3) Billions of Cubic Feet	Remarks
Normandville	Gething	2.5	20	5	2	
	Triassic	8.7	15	5	7	
	Rundle	9.4	10	5	8	
Obed	Rundle	12.3	10	10	10	Presently considered beyond economic reach.
Oberlin	Viking	0.5	25	5	0.4	
	Basal Blairmore	2.3(i) 1.4(ii)	20	5	0.9	(i) Original (ii) Less 0.9 Bcf produced to December 31, 1957. Supplies local utility.
Okotoks	Wabamun	375	10	60(i)	135	(i) Very high acid gas content.
Olds	Wabamun	83.3	10	20	60	
Oyen	Viking	10.5	20	5	8	
Paddle River	Jurassic	18.4	20	5	14	
	Mississippian	4.0	20	5	3	
Parkland	Rundle	19.6	10	15	15	
Pembina	Belly River	32.6(i) 32.3(ii)	15	5	26	(i) Original (ii) Less 0.3 Bcf produced to December 31, 1957.
	Cardium Solution	1832.2(i) 1766.0(ii)	60	40	400	(i) Original (ii) Less 66.2 Bcf produced to December 31, 1957.
	Basal Blairmore	2.8	25	5	2	
	Rundle	4.4	15	10	3	
Pendant d'Orielle	Bow Island	214.0(i) 169.1(ii)	20	5	120	Exporting to Montana. (i) Original (ii) Less 44.9 Bcf produced to December 31, 1957.
Phil Can	Gething	11.8	20	5	9	Presently considered beyond economic reach.
	Mississippian	5.6	15	5	4	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Pigeon Lake	Leduc	13.1	10	15	10	
Pincher Creek	Rundle	2642.7(i) 2636.5(ii)	14	25	1700	(i) Original (ii) Less 6.2 Bcf produced to December 31, 1957.
Pine Creek	Wabamun	3.0	10	25	2	
	Leduc	404.0	10	45	200	
Pouce Coupe	Cadotte	258.4(i) 252.1(ii)	10	5	215	Exporting to British Columbia and United States. (i) Original (ii) Less 6.3 Bcf produced to December 31, 1957.
	Cadomin	12.4	15	5	10	
Pouce Coupe South	Doe Creek	8.4	25	5	6	
	Cadotte	88.9(i) 82.6(ii)	10	5	70	Exporting to British Columbia and United States. (i) Original (ii) Less 6.3 Bcf produced to December 31, 1957.
	Cadomin	11.7	10	5	10	
	Triassic	12.4	15	5	10	
Princess	Bow Island	6.6	20	5	5	
	Basal Colorado	41.0(i) 39.8(ii)	20	5	30	(i) Original (ii) Less 1.2 Bcf produced to December 31, 1957.
	Basal Blairmore	117.6(i) 117.1(ii)	10	5	100	(i) Original (ii) Less 0.5 Bcf produced to December 31, 1957.
	Rundle Associated	6.6	20	5	5	
	Jefferson Associated	41.0(i) 37.7(ii)	20	5	28	(i) Original (ii) Less 3.3 Bcf produced to December 31, 1957.
Provost	Viking	698.6(i) 697.6(ii)	20	5	530	Exporting to Eastern Canada. (i) Original (ii) Less 1.0 Bcf produced to December 31, 1957.
	Blairmore	12.4	15	5	10	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Redwater	Viking	28.7(i) 28.1(ii)	25	5	20	(i) Original (ii) Less 0.6 Bcf produced to December 31, 1957.
	Leduc Solution	258.7(i) 221.5(ii)	40	50	59	(i) Original (ii) Less 37.2 Bcf produced to December 31, 1957. Reserves adjusted by 1.25 factor to convert to 1000 BTU basis.
Rochester	Viking	5.3	20	5	4	Presently considered beyond economic reach.
	Blairmore	26.7	25	5	19	
	Wabamun	5.8	10	5	5	
Rolling Hills	Bow Island	26.0	15	5	21	
	Basal Colorado	7.4	15	5	6	
Rosebud	Viking	19.7	20	5	15	
	Blairmore	24.8	15	5	20	
Rosedale	Viking	9.2	20	5	7	
	Blairmore	21.3(i) 20.7(ii)	15	5	16.6	(i) Original (ii) Less 0.6 Bcf produced to December 31, 1957. Supplies local utility.
Round Valley	Basal Blairmore	11.7	10	5	10	
Rycroft	Gething Non-Associated and Associated	16.2(i) 14.2(ii)	15	5	11.2	(i) Original (ii) Less 2.0 Bcf produced to December 31, 1957. Supplies local utility.
St. Albert	Viking	2.5	20	5	2	
	Lower Cretaceous	56.0(i) 40.3(ii)	10	5	33	(i) Original (ii) Less 15.7 Bcf produced to December 31, 1957.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
St. Paul	Blairmore	2.7(i) 1.2(ii)	20	5	0.6	Supplies local utility. (i) Original (ii) Less 1.5 Bcf produced to December 31, 1957.
Saddle Hills	Peace River	26.9	10	5	23	Presently considered beyond economic reach.
	Lower Cretaceous	2.5	15	5	2	
Samson	Basal Blairmore Associated and Non-Associated	16.1(i) 15.4(ii)	20	10	11	(i) Original (ii) Less 0.7 Bcf produced to December 31, 1957.
Sarcee	Rundle	208.3	10	20	150	
Savanna Creek	Rundle	814.8	10	25	550	
Sibbald	Viking	46.0	20	5	35	
	Blairmore	5.3	20	5	4	
Smith Coulee	Bow Island	46.6(i) 45.3(ii)	25	5	32	Exporting to Montana. (i) Original (ii) Less 1.3 Bcf produced to December 31, 1957.
Stettler	Viking	4.2	25	5	3	
	Nisku Solution	25.4(i) 23.6(ii)	35	25	11	(i) Original (ii) Less 1.8 Bcf produced to December 31, 1957.
	Leduc Solution	10.2(i) 9.3(ii)	35	30	4	(i) Original (ii) Less 0.9 Bcf produced to December 31, 1957.
Stolberg	Rundle	61.5	10	15	45	Presently considered beyond economic reach.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
STURGEON LAKE	LEDUC SOLUTION	42.7(I) 41.7(II)	40	35	16	(I) ORIGINAL (II) LESS 1.0 BCF PRODUCED TO DECEMBER 31, 1957.
STURGEON LAKE SOUTH	GETHING	16.1	15	5	13	
	CADOMIN	11.2	15	5	9	
	TRIASSIC NON-ASSOCIATED	3.5	10	5	3	
	TRIASSIC SOLUTION	18.6(I) 18.5(II)	35	25	9	(I) ORIGINAL (II) LESS 0.1 BCF PRODUCED TO DECEMBER 31, 1957.
	PERMO-PENN	2.6	20	5	2	
	LEDUC ASSOCIATED	7.4	10	25	5	
	LEDUC SOLUTION	243.8(I) 239.1(II)	35	35	100	(I) ORIGINAL (II) LESS 4.7 BCF PRODUCED TO DECEMBER 31, 1957.
STURGEON LAKE SOUTH GENERAL AREA	GETHING	61.9	15	5	50	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	TRIASSIC	7.0	10	5	6	
	PERMO-PENN	2.6	20	5	2	
SUFFIELD	MILK RIVER	44.9(I) 42.8(II)	25	5	30	SUPPLIES DEPARTMENT OF NATIONAL DEFENCE STATION. (I) ORIGINAL (II) LESS 2.1 BCF PRODUCED TO DECEMBER 31, 1957.
SUNDRE	MISSISSIPPIAN ASSOCIATED	26.2	10	15	20	
	MISSISSIPPIAN SOLUTION	64.0(I) 62.4(II)	35	25	30	(I) ORIGINAL (II) LESS 1.6 BCF PRODUCED TO DECEMBER 31, 1957.
SYLVAN LAKE	BASAL BLAIRMORE	49.3	10	10	40	
	MISSISSIPPIAN	11.1	20	10	8	
	DEVONIAN	5.6	10	20	4	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
TANGENT	CADOTTE	15.1	30(I)	5	10	(I) HIGH LOSS DUE TO LOW RESERVOIR PRESSURE.
	GETHING	130.1	15	5	105	
	TRIASSIC	64.7	20	5	50	
THREE HILLS CREEK	BELLY RIVER	6.2	15	5	5	
	VIKING	6.5	20	5	5	
	MISSISSIPPIAN	29.3	10	5	25	
TURIN	BOW ISLAND	5.0	15	5	4	
	BASAL BLAIRMORE	21.1	10	5	18	
	ELLIS	5.0	15	5	4	
	RUNDLE	2.5	15	5	2	
TURNER VALLEY	RUNDLE GAS CAP	-	-	20	200	AFTER DEDUCTING PRODUCTION TO DECEMBER 31, 1957.
	RUNDLE SOLUTION	-	-	38	140	
VIKING-KINSELLA	VIKING	1004.3(I) 709.0(II)	25	5	435	(I) ORIGINAL (II) LESS 295.3 BCF PRODUCED DECEMBER 31, 1957.
	BLAIRMORE	19.8	15	5	16	
	DEVONIAN	5.3	20	5	4	
WARBURG	BASAL BELLY RIVER	3.5	10	5	3	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	VIKING	10.5	10	5	9	
WATERTON	RUNDLE	1555.5	10	50	700	
WATTS	VIKING	1.8(I) 1.4(II)	20	5	1.0	SUPPLIES LOCAL UTILITY. (I) ORIGINAL (II) LESS 0.4 BCF PRODUCED TO DECEMBER 31, 1957.
	MISSISSIPPIAN	1.3	20	5	1	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
WAYNE	VIKING	13.2	20	5	10	
	BASAL BLAIRMORE ASSOCIATED	13.6	10	10	11	
	BASAL BLAIRMORE SOLUTION	25.7(I) 25.5(II)	35	15	14	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH. (I) ORIGINAL (II) LESS 0.2 BCF PRODUCED TO DECEMBER 31, 1957.
WEST DRUMHELLER	BASAL BLAIRMORE	12.4	15	5	10	
	NISKU ASSOCIATED	9.1	10	15	7	
	NISKU SOLUTION	30.4(I) 27.4(II)	45	25	11	(I) ORIGINAL (II) LESS 3.0 BCF PRODUCED TO DECEMBER 31, 1957.
	LEDUC SOLUTION	2.6(I) 2.4(II)	40	25	1	(I) ORIGINAL (II) LESS 0.2 BCF PRODUCED TO DECEMBER 31, 1957.
WESTEROSE	LEDUC ASSOCIATED	125.0	10	20	90	
	LEDUC SOLUTION	121.0(I) 117.6(II)	30	25	61	(I) ORIGINAL (II) 6.0 BCF PRODUCED TO DECEMBER 31, 1957. INJECTED 2.6 BCF TO DECEMBER 31, 1957. NET PRODUCTION 3.4 BCF.
WESTEROSE SOUTH	LEDUC	1307.1	10	15	1000	
WESTLOCK	VIKING	282.1(I) 281.0(II)	25	5	200	(I) ORIGINAL (II) LESS 1.1 BCF PRODUCED TO DECEMBER 31, 1957.
	BASAL BLAIRMORE	2.6	20	5	2	
WEST PRAIRIE	CADOTTE	17.6	10	5	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	GETHING	5.8	10	5	5	

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Westward Ho	Mississippian Non-Associated	40.6	10	15	31	
	Mississippian Solution	34.6(i) 33.4(ii)	35	25	16	(i) Original (ii) Less 1.2 Bcf produced to December 31, 1957.
Whitelaw	Gething	34.7(i) 32.6(ii)	15	5	26	Supplies local utility. (i) Original (ii) Less 2.1 Bcf produced to December 31, 1957.
	Triassic	49.1	10	5	42	
Wildmere	Lower Cretaceous	13.5(i) 7.0(ii)	20	5	4.1	Supplies local utility. (i) Original (ii) Less 6.5 Bcf produced to December 31, 1957.
Wildunn Creek	Viking	19.7	20	5	15	
Willesden Green	Cardium Solution	20.7(i) 20.5(ii)	35	25	10	Presently considered beyond economic reach. (i) Original (ii) Less 0.2 Bcf produced to December 31, 1957.
Wimborne	Viking	1.4	25	5	1	
	Nisku Associated	2.8	15	15	2	
	Leduc Associated	333.3	10	60(i)	120	(i) Very high acid gas content.
Windfall	Viking	4.2	25	5	3	
	Leduc Associated	507.9	10	30(i)	320	(i) High acid gas and distillate content.

1	2	3	4	5	6	7
FIELD OR AREA	ZONE (5)	ESTIMATED ORIGINAL GAS IN PLACE BILLIONS OF CUBIC FEET	DISCOUNT FOR RESERVOIR LOSS PER CENT	DISCOUNT FOR SURFACE LOSS, ETC., (4) PER CENT	DISPOSABLE GAS (3) BILLIONS OF CUBIC FEET	REMARKS
Wizard Lake	Viking	2.5	15	5	2	
	Basal Blairmore	9.3	10	5	8	
	Leduc Solution	208.5(i) 197.8(ii)	40	30	80	(i) Original (ii) Less 10.7 Bcf produced to December 31, 1957.
Wood River	Basal Blairmore	46.8	10	5	40	
Other reserves less than 10 billion cubic feet not listed above					236	Estimated to be within economic reach.
Other reserves less than 10 billion cubic feet not listed above					528	Presently considered beyond economic reach.
				TOTAL	21,048.4	

GENERAL NOTES:

1. Unless otherwise noted reservoir loss is calculated as 10% of original gas in place except in particular cases where the following losses pertain:

   Sand Thickness 10-15 feet Reservoir Loss 15%, Sand Thickness 5-10 feet Reservoir Loss 20%,

   Sand Thickness 0-5 feet Reservoir Loss 25%.

2. Surface loss is taken as 5% for all dry gas, and varies for wet gas depending upon its composition.
3. Disposable reserves as at January 1st, 1958 after deducting production to December 31st, 1957.
4. Unless otherwise noted surface discount factors in excess of 5% are due to extraction of heavy hydrocarbons.
5. Refer to the table of formations shown in Figure III-2 for the Stratigraphic Relationship of the Zones.

STAFF ESTIMATE OF RESERVES OF LIQUID HYDROCARBONS

DECEMBER 31, 1957

A trend in the distribution of gas reserves by types has become evident in the past few years. By classifying each gas reserve into four types of gas, the percentage distribution among types as of 1950 and as of 1957 is as follows:

Type of Reserve	Percentage of Total Reserves 1950	1957
Non-associated "Dry" gas	58	50
Condensate gas	27	24
Associated gas	9	16
Solution gas	6	10

wet gas requires extensive processing.

It may be seen that the percentage of dry gas reserves has declined from 58 in 1950 to 50 in 1957. With the apparent shifting of exploration from the plains area to the foothills and mountain areas of the Province it is expected that more "wet" gas reserves will be discovered and that the percentage of gas requiring processing for removal of liquid hydrocarbons will increase beyond the current 50 per cent of total reserves. The reserves of the liquid hydrocarbons are directly dependent upon the reserves of condensate, associated, and solution gas.

The liquid hydrocarbon reserves as of December 31, 1957, are estimated to be 15,550 million gallons. The recoverable reserves are classified as follows:

(1)	Propane	5,090 million gallons
(2)	Butanes	4,800 million gallons
(3)	Pentanes Plus	5,660 million gallons

A breakdown of the reserves of liquid hydrocarbons by fields is shown in Table J-1

The following method was used to estimate the recoverable liquid hydrocarbon reserves in the fields where there are no plants at present.

(1) Recoverable propane estimated to be 50 per cent of propane in the producible gas reserves.

(2) Recoverable butanes estimated to be 90 per cent of butanes in the producible gas reserves.

(3) Recoverable pentanes plus estimated to be 100 per cent of pentanes plus present in the producible gas reserves.

In the fields where plant statistics were available average recoveries were used to estimate the recoverable liquid hydrocarbon reserves.

TABLE J-1

RESERVES OF LIQUID HYDROCARBONS FROM

NATURAL GAS IN THE PROVINCE OF ALBERTA

DECEMBER 31, 1957

Field	Recoverable Propane Million Gallons	Recoverable Butanes Million Gallons	Recoverable Pentanes Plus Million Gallons
Acheson	85	45	20
Alhambra	30	25	15
Bonnie Glen	630	440	260
Calgary	10	10	10
Campbell-Namao	15	10	5
Cessford	-	-	190
Crossfield	50	55	55
Eagle Hill	20	15	15
Erskine	25	15	20
Fenn-Big Valley	75	115	60
Gilby	80	70	50
Glen Park	15	15	10
Golden Spike	160	130	60
Harmattan-Elkton	525	655	540
Homeglen-Rimbey	335	440	440
Hussar	-	-	15
Innisfail	30	30	10
Jumping Pound	-	-	75
Leduc-Woodbend	845	585	295

Field	Recoverable Propane Million Gallons	Recoverable Butanes Million Gallons	Recoverable Pentanes Plus Million Gallons
Morinville	25	20	10
Nevis	215	220	195
Pembina	415	280	205
Pincher Creek	320	370	400
Provost	-	-	35
Redwater	200	200	75
Sarcee	25	15	25
Stettler	15	25	10
Sturgeon Lake	20	20	10
Sturgeon Lake South	85	70	25
Sundre	20	15	10
Turner Valley	110	-	355*
Waterton	120	220	1,650
West Drumheller	30	25	10
Westerose	140	140	75
Westerose South	35	25	25
Westward Ho	25	20	10
Wimborne	105	170	125
Windfall	95	165	195
Wizard Lake	160	145	70
TOTALS	5,090	4,800	5,660

* 45# RVP Product

45 lb
Reid Vapor
Pressure

TRENDS IN THE GROWTH OF VIRGIN RECOVERABLE RESERVES OF OIL AND CONDENSATE AND NATURAL GAS IN THE PROVINCE OF ALBERTA

Present Reserves of Oil and Condensate

A review of data on the recent growth of Alberta oil and condensate reserves shows that as of December 31, 1957, the drilling of a total of 4,045 wildcat wells has resulted in the discovery of some 4 billion barrels of recoverable virgin reserves of oil and condensate. The increase in new reserves during 1957 amounted to some 283 million barrels, of which some 66 million barrels is attributable to newly discovered pools or fields. Data for the past five years shows that an average of approximately 423 million barrels of new or additional reserves have been added to the total virgin reserves each year.

The remaining recoverable reserves and condensate after allowance for the cumulative production of some 812 million barrels are estimated to be about 3.1 billion barrels as of December 31, 1957. The net increase in remaining reserves during 1957 is in excess of 145 million barrels.

The distribution of the remaining recoverable reserves of oil and condensate by broad gravity ranges is as follows:

Type	Millions of Barrels
Light and Medium Oils	2,893
Heavy Oil	34
Condensate	185
Total	3,112

These reserve figures represent the total of carefully compiled estimates for all individual pools within the Province. Each estimate is based on all available data on reservoir and production characteristics and refers to proven economically recoverable oil. The significance of the reserve estimates is indicated by considering the ratio of the year-end remaining recoverable reserves to annual production. This ratio has changed from 10 years, in 1946, through a figure of some 50 years in 1948 to its present value of approximately 23 years.

Future Reserves of Oil and Condensate

An indication of the extent of the potential reserves of recoverable oil underlying Alberta may be had by considering the volumes of favourable oil containing sediments in Alberta. To this may be assigned an accumulation factor for oil, based on experience in the United States, and assuming that the same degree of oil accumulation will occur in Alberta. A second approach, which can be related to the number of wildcats drilled at any given time, is based on the success of wildcat wells and the area of prospective oil and gas lands in Alberta.

In a submission made to "The Royal Commission on Canada's Economic Prospects", in October, 1955, the Board staff estimated that there existed in Alberta some 200,000 square miles of land favourable for the prospecting of oil and gas and that this area contained some 270,000 cubic

miles of sediment favourable for the accumulation of oil and gas reserves. By applying a minimum and maximum accumulation factor of 40,000 to 55,000 barrels of oil per cubic mile of sediments to the total volume of favourable sediments a potential reserve figure of 10.8 billion to 14.9 billion barrels of recoverable oil is calculated for Alberta. These reserve estimates refer to the total gross volumes of recoverable oil with no deduction made for the oil produced during any period.

The second approach employed in estimating the future recoverable reserves of crude oil is based upon the record of success of wildcat wells and the area of prospective oil and gas lands in the Province. The density of wildcat drilling has increased steadily from one wildcat per 121 square miles (of the 200,000 square miles of potential oil bearing sediments) as of December 31, 1951, to one wildcat well per 49 square miles as at December 31, 1957. The Board considers that this density will increase to about one wildcat per 10 square miles before the increase in the cumulative virgin recoverable reserves of oil and condensate per wildcat well becomes negligible. This would give a total of some 20,000 wildcat wells for the 200,000 square miles of potential oil area.

Statistical data dealing with the total number of wildcat wells drilled and the recoverable reserves of oil and condensate discovered to December 31, 1957, show that 4,045 wildcat wells have resulted in the discovery of approximately 4 billion barrels of recoverable virgin reserves.

This is an overall discovery rate of almost one million barrels of oil for every wildcat well drilled.

The trend in the growth of the virgin recoverable reserves of oil and condensate per wildcat drilled is shown in Figure M-1. The annual plots are based on data given in Table M-1. The line A-A1 indicates the rate of the virgin reserves discovered per year for the number of wildcat wells drilled each year. This line is erratic due to its sensitivity to discoveries of large reserves in any one year. The line B-B1 is the relationship of the cumulative recoverable virgin reserves discovered to the cumulative number of wildcat wells drilled and illustrates an overall discovery rate of approximately one million barrels for each wildcat well drilled.

Figure M-2 illustrates the trend in the growth of cumulative recoverable virgin reserves with the cumulative number of wildcat wells drilled. The line DE is the trend in the growth of virgin recoverable reserves to date. The line DEF is an estimate of the growth trend that is anticipated with the drilling of a total of 20,000 wildcat wells. The change in slope of the curve reflects an expected reduction in the rate of discovery as the remaining undiscovered reserves decrease.

The conclusions of this approach are:

(1) that the drilling of an estimated 20,000 wildcat wells will ultimately result in the discovery of

some 14 billion barrels of recoverable oil and condensate; and

(2) that the extent to which these reserves are known at any time will depend on the total number of wildcat wells drilled at the same point in time.

Trends in the Growth of Potential Production and Production of Oil and Condensate

Figure M-3 which is based on data given in Table M-2, illustrates the trends in the growth of the potential production and actual production of oil and condensate in the Province since 1946. For the years prior to 1949 the markets for Alberta oil and condensate were sufficient to absorb the total provincial production capacity. With the discovery and the rapid development of the Leduc, Redwater and other fields, the provincial production capacity during the period 1949 to 1952 exceeded the requirements of the Western Canadian markets by a wide margin. The construction of pipe lines to Eastern Canada and to the West Coast during the period 1952 and 1953 made Alberta oil available to Ontario, British Columbia and Washington, U.S.A., markets and thus a larger portion of Alberta's production capacity was utilized. In 1954 the annual average daily production amounted to 70 per cent of the provincial productive capacity. Since 1954 the productive capacity has increased with the discovery of new fields at a faster rate than the growth in markets. In 1957 the annual production rate was equal to only 50 per cent of the maximum

efficient rate of production of some 756,000 barrels per day.

The line GH-G in Figure M-3 illustrates the growth in potential production from 18,000 barrels per day in 1946 to 756,000 barrels per day in 1957. The line GH-H illustrates the growth in actual production from 18,000 barrels per day in 1946 to 376,000 barrels per day in 1957. The line J-J1 illustrates the percentage relationship of the actual production to the potential production for the period 1946 to 1957.

Trends in the Growth of Recoverable Reserves of Oil and Condensate

Figure M-4 which is based on data given in Table M-2 illustrates the trends in the growth of recoverable reserves of oil and condensate in the Province of Alberta. The line K-K1 shows the growth in virgin recoverable reserves from 157 million barrels in 1946 to 3.9 billion barrels in 1957. This figure compares favourably with the figure of 4 billion barrels in 1957 as predicted in the Board's submission to "The Royal Commission on Canada's Economic Prospects", in 1955. The year-end remaining recoverable reserves during the same period increased from 72 million barrels to 3.1 billion barrels and is shown on the graph as line L-L1, The difference between the virgin and remaining recoverable reserves represents cumulative production as of December 31, 1957, of some 812 million barrels.

The annual production of oil and condensate, illustrated by line M-M1, has increased almost steadily from 7 million

barrels in 1946 to 137 million barrels in 1957. In 1957 the rate of production fell below that for 1956. This decline in rate is believed to be temporary in nature and not indicative of a long term trend of a stable or decreasing rate of production.

The line 0-01 illustrates the relationship of annual production to year-end remaining recoverable reserves for the period 1946 to 1957. The annual rate of reserve withdrawal for the past five years has averaged between 4 per cent and 4.5 per cent of the year-end remaining recoverable reserves. In 1957 this rate had dropped to 4.4 per cent as compared to 4.86 per cent in 1956.

Trends in the Growth of the Reserves of Natural Gas

Statistical data dealing with the number of wildcat wells drilled, and the initial disposable gas reserves discovered to December 31st, 1957, are presented in Table M-3. The table indicates that the drilling of 4,045 wildcat wells resulted in the discovery of some 22.2 trillion cubic feet of initial disposable gas reserves. This is an overall discovery rate of 5.5 billion cubic feet of gas for every wildcat well drilled and agrees closely with the corresponding rates established in June, 1953, June, 1955, and September, 1956. These rates were 5.3, 5.4 and 5.6 billion cubic feet of gas per wildcat well respectively.

Figure M-5 shows a plot of the cumulative initial disposable reserves of natural gas by years using the data

listed in Table M-3. For comparative purposes the corresponding graphs published in four most recent Board Reports have been included. The curves indicate that a time lag of several years occurs before new discoveries may be fully evaluated. It is apparent that reserves discovered previous to 1953 have been almost completely evaluated, while those discovered subsequent to that time likely will be assigned a higher value in total when re-examined in the future.

Figure M-6 is a revision of similar plots contained in previous Board Reports. It shows the initial disposable reserves per wildcat well drilled for the years 1942 to 1957 inclusive. The dashed line "A-A" indicates the ratio of the initial disposable reserves discovered per year to the number of wildcat wells drilled in the same year. It is erratic due to the sensitivity to discoveries of large reserves in any particular year. When the data are plotted on a cumulative basis as indicated by the line "B-B", a definite trend is established. This curve shows that at December 31st, 1957, due to the drilling of 4,045 wildcat wells which resulted in the discovery of 22.2 trillion cubic feet of initial disposable gas reserves, the cumulative rate of discovery was 5.5 billion cubic feet for each wildcat well drilled. Due to the time-lag effect, previously mentioned, the 1953, 1955 and 1956 values have increased from 5.3, 5.4 and 5.6 billion cubic feet per wildcat well drilled to 7.0, 6.8 and 6.0 billion cubic feet per wildcat well respectively. The Board

believes it realistic to assume that for the next few years at least, six billion cubic feet of natural gas reserves will be developed per wildcat well.

Figure M-7 shows the growth of cumulative initial disposable gas reserves with the cumulative number of wildcat wells drilled. The line DEF is an estimate of the growth trend which was constructed as a conservative forecast on the basis of data available for the Board's November, 1953, report. On the basis of current data the Board is of the opinion that the projection indicated by line ABC is reasonable. The change in slope of the curve indicates an expected diminishing rate of growth of initial disposable reserves of natural gas per wildcat well drilled in future years from the present expectation of six billion cubic feet per wildcat well. At the present rate of 350 to 400 wildcat wells per year the diminishing rate is not expected to be noticeable until five to ten years hence.

As a check on the projection, a comparison may be made with the estimated future oil reserves, previously discussed. At December 31st, 1957, the cumulative initial recoverable gas reserves and the cumulative virgin recoverable reserves of oil and condensate were 22.2 trillion cubic feet and four billion barrels respectively. The reserves gas-oil (plus condensate) ratio is 5,500 cubic feet per barrel. Applying this ratio to the range of estimates given for the cumulative virgin recoverable reserves of oil and condensate after the

drilling of 20,000 wildcat wells, one obtains the corresponding range of cumulative initial recoverable gas reserves of 60 to 83 trillion cubic feet. The Board believes this alternate approach to the reserves projection to be indicative of ultimate possibilities.

TABLE M-1

TRENDS IN THE GROWTH OF VIRGIN RECOVERABLE RESERVES OF OIL AND CONDENSATE
PROVINCE OF ALBERTA
(Based on year-end known reserves)

Year (1)	Virgin Recoverable Reserves Discovered Per Year (MM Bbls.) (2)	Cumulative Recoverable Virgin Reserves (MM Bbls.) (3)	Wildcats Drilled Per Year (4)	Cumulative Wildcats Drilled (5)	Virgin Reserves Discovered Per Wildcat Per Year (MM Bbls.) (6)	Cumulative Virgin Reserves Discovered Per Wildcat (MM Bbls.) (7)
1947	114	271	71	638	1.606	0.425
1948	342	613	126	764	2.714	0.802
1949	433	1,046	209	973	2.072	1.075
1950	202	1,248	224	1,197	0.902	1.043
1951	272	1,520	461	1,658	0.590	0.917
1952	290	1,810	469	2,127	0.618	0.851
1953	435	2,245	399	2,526	1.090	0.889
1954	360	2,605	351	2,877	1.026	0.905
1955	429	3,034	346	3,223	1.240	0.941
1956	607	3,641	384	3,607	1.581	1.009
1957	283	3,924	438	4,045	0.646	0.970

TABLE M-2

TRENDS IN THE GROWTH OF POTENTIAL PRODUCTION
ACTUAL PRODUCTION AND RECOVERABLE RESERVES OF OIL AND CONDENSATE
PROVINCE OF ALBERTA

Year (1)	Recoverable Virgin Reserves (MM Bbls.) (2)	Remaining Recoverable Reserves (MM Bbls.) (3)	Annual Production (MM Bbls.) (4)	Cumulative Production (MM Bbls.) (5)	Potential Production B/D (M Bbls.) (6)	Actual Production B/D (M Bbls.) (7)	Per Cent Annual Production of Remaining Rec. Reserves (8)	Per Cent Production of Potential (9)
1946	157	72	7	85	18	18	9.72	100
1947	271	180	6	91	18	18	3.33	100
1948	613	512	10	101	29	29	1.95	100
1949	1,046	925	20	121	79	54	2.16	68
1950	1,248	1,100	27	148	146	74	2.45	51
1951	1,520	1,326	46	194	203	126	3.47	62
1952	1,810	1,557	59	253	264	161	3.79	61
1953	2,245	1,915	77	330	317	211	4.02	67
1954	2,605	2,187	88	418	343	240	4.02	70
1955	3,034	2,503	113	531	492	310	4.51	63
1956	3,641	2,966	144	675	684	393	4.86	57
1957	3,924	3,112	137	812	756	376	4.40	50

TABLE M-3

OIL AND GAS CONSERVATION BOARD

TRENDS IN WILDCAT DRILLING AND GROWTH OF DISPOSABLE GAS RESERVES IN THE PROVINCE OF ALBERTA

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD	DISPOSABLE GAS RESERVES AS OF DECEMBER 31, 1957 BCF	SALES TO DECEMBER 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
PRIOR TO 1930		172	MEDICINE HAT, BOW ISLAND, BROOKS-TILLEY, VIKING-KINSELLA (VIKING), TURNER VALLEY FOREMOST, POUCE COUPE, WAINWRIGHT	2373	910	3283	3283
1930	29	201					3283
1931	9	210					3283
1932	6	216	PINHORN	3	-	3	3286
1933	7	223					3286
1934	3	226	LLOYDMINSTER	5	-	5	3291
1935	2	228					3291
1936	8	236					3291
1937	15	251	WILDMERE	4	6	10	3301
1938	12	263					3301
1939	18	281					3301
1940	23	304	PRINCESS	158	-	158	3459
1941	20	324	SUFFIELD	30	2	32	3491
1942	43	367	OYEN	8	-	8	
1943	34	401	OTHER SMALL FIELDS	4	-	4	3503
1944	56	457	ATHABASCA	3	1	4	3507
			BLACK BUTTE	31	9	40	
1945	56	513	JUMPING POUND	518	73	591	4138
			PATRICIA	10	-	10	
1946	54	567	OTHER SMALL FIELDS	4	-	4	4152
			BEAVERHILL LAKE (VIKING)	90	-	90	
			BROOKS NORTH-EAST (SUNBURST)	4	1	5	
			LINDBERGH	3	2	5	
			PENDANT D'OREILLE	120	43	163	
			PROVOST	540	1	541	4956

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD	DISPOSABLE GAS RESERVES AS OF DECEMBER 31, 1957 BCF	SALES TO DECEMBER 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1947	71	638	FAIRYDELL-BON ACCORD	76	4	80	
			LEDUC-WOODBEND	639	103	742	
			MANYBERRIES	45	3	48	
			MEDICINE HAT (BOW ISLAND AND ELLIS)	20	-	20	
			ST. PAUL	1	1	2	
			SMITH COULEE	32	1	33	
			OTHER SMALL FIELDS	7		7	5888
1948	126	764	BROOKS NORTH-EAST (BOW ISLAND)	5	-	5	
			ELK POINT	1	-	1	
			MORINVILLE	87	17	104	
			PINCHER CREEK	1700	-	1700	
			REDWATER	79	2	81	
			DOWLING LAKE	1	-	1	
			OTHER SMALL FIELDS	9	-	9	7789
1949	209	973	BONNYVILLE	3	1	4	
			BOYLE-MUSTANG-AMISK LAKE	20	-	20	
			CALAHOO	13	-	13	
			CAMPBELL-NAMAO	40	-	40	
			CASTOR	20	-	20	
			CESSFORD	1109	-	1109	
			EXCELSIOR	67	-	67	
			GOLDEN SPIKE	99	-	99	
			JOARCAM	65	-	65	
			LAC LA BICHE	45	-	45	
			NORMANDVILLE (GETHING)	2	-	2	
			OBERLIN	1	1	2	
			ROCHESTER	28	-	28	
			STETTLER	18	-	18	
			WESTLOCK (VIKING)	200	1	201	
			OTHER SMALL FIELDS	49	-	49	9571
1950	224	1197	ACHESON	91	1	92	
			ATHABASCA EAST	2	-	2	
			COUNTESS	54	-	54	
			DUHAMEL	12	-	12	
			FENN BIG VALLEY	90	1	91	
			LEAHURST	7	1	8	
			ROLLING HILLS (BOW ISLAND)	21	-	21	
			SIBBALD	39	-	39	
			TURIN (RUNDLE)	2	-	2	
			WHITELAW	68	1	69	
			OTHER SMALL FIELDS	60	-	60	10021

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD	DISPOSABLE GAS RESERVES AS OF DECEMBER 31, 1957 BCF	SALES TO DECEMBER 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1951	461	1658	ATLEE-BUFFALO (VIKING)	70	-	70	
			BELLOY (MISSISSIPPIAN)	15	-	15	
			BONNIE GLEN	653	17	670	
			CLIVE	16	-	16	
			DUCHESS	19	-	19	
			ETZIKOM (BOW ISLAND)	140	4	144	
			FORT SASKATCHEWAN	120	19	139	
			GLEN PARK	15	1	16	
			HAMELIN CREEK	39	-	39	
			HARMATTAN-ELKTON (NON-ASSOCIATED)	55	-	55	
			HERCULES	19	-	19	
			MAJEAU LAKE	12	-	12	
			MILLET	15	-	15	
			NEW NORWAY	13	-	13	
			OKOTOKS	135	-	135	
			ST. ALBERT	35	15	50	
			TANGENT	165	-	165	
			TURIN (BOW ISLAND, BASAL BLAIRMORE, ELLIS)	26	-	26	
			VIKING-KINSELLA (BLAIRMORE AND DEVONIAN)	20	1	21	
			WATTS	2	-	2	
			WESTLOCK (BLAIRMORE)	2	-	2	
			WIMBORNE (NISKU GAS CAP)	2	-	2	
			WIZARD LAKE	90	6	96	
			OTHER SMALL FIELDS	66	-	66	11828
1952	469	2127	BELLOY (CADOTTE AND GETHING)	54	-	54	
			BINDLOSS (VIKING)	280	1	281	
			BITTERN LAKE	26	-	26	
			CHIGWELL	25	-	25	
			COLD LAKE	2	1	3	
			COMREY	45	-	45	
			DIXONVILLE	27	-	27	
			DUVERNEY	1	1	2	
			EAGLESHAM (PEACE RIVER AND MISSISSIPPIAN)	8	-	8	
			ERSKINE	48	-	48	
			GHOST PINE	15	-	15	
			GORDONDALE (CADOTTE)	40	-	40	
			HACKETT	45	-	45	
			HAIRY HILL	12	1	13	
			HAMILTON LAKE	40	-	40	
			HUSSAR (LOWER CRETACEOUS)	160	-	160	

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD	DISPOSABLE GAS RESERVES AS OF DECEMBER 31, 1957 BCF	SALES TO DECEMBER 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1952 (CONT)			MALMO	18	-	18	
			MINNEHIK-BUCK LAKE	102	-	102	
			NEVIS	550	-	550	
			OLDS	60	-	60	
			PHIL CAN	13	-	13	
			PIGEON LAKE	10	-	10	
			RYCROFT	11	2	13	
			STURGEON LAKE	16	-	16	
			STURGEON LAKE SOUTH GENERAL AREA	58	-	58	
			WEST DRUMHELLER	29	-	29	
			WESTEROSE	151	-	151	
			WILDUNN CREEK	15	-	15	
			OTHER SMALL FIELDS	77	-	77	13772
1953	399	2526	ATLEE-BUFFALO (BASAL BLAIRMORE)	70	-	70	
			DONALDA	12	-	12	
			DYBERG	14	-	14	
			ENCHANT	11	-	11	
			EYREMORE	12	-	12	
			GILBY	196	-	196	
			GORDONDALE (GETHING AND CADOTTE)	80	-	80	
			HARMATTAN-ELKTON (MISSISSIPPIAN GAS CAP)	780	-	780	
			HOMEGLEN-RIMBEY	770	-	770	
			JOFFRE (VIKING SOLUTION)	12	-	12	
			KESSLER	50	-	50	
			LITTLE SMOKY RIVER	14	-	14	
			PARKLAND	15	-	15	
			PEMBINA	431	-	431	
			POUCE COUPE SOUTH	96	6	102	
			ROSEDALE	24	1	25	
			SAMSON	11	1	12	
			STURGEON LAKE SOUTH	141	-	141	
			SYLVAN LAKE	52	-	52	
			THREE HILLS CREEK	35	-	35	
			WESTEROSE SOUTH	1000	-	1000	
			WOOD RIVER	40	-	40	
			OTHER SMALL FIELDS	98	-	98	17744

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD	DISPOSABLE GAS RESERVES AS OF DECEMBER 31, 1957 BCF	SALES TO DECEMBER 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1954	351	2877	Alexander	35	8	43	
			Alhambra	27	-	27	
			Bellshill Lake	100	-	100	
			Bindloss (Basal Blairmore)	20	-	20	
			Braeburn	75	-	75	
			Calgary (D-1)	325	-	325	
			Garrington	40	-	40	
			Gem	11	-	11	
			Grassy Island Lake	20	-	20	
			Harmattan-Elkton (Mississippian Solution)	85	-	85	
			Holborne	24	-	24	
			Saddle Hills	25	-	25	
			Sarcee	150	-	150	
			Savanna Creek	550	-	550	
			Wayne	35	-	35	
			Westward Ho (Rundle Non-Associated)	31	-	31	
			Wimborne (Viking and Leduc)	121	-	121	
			Other small fields	45	-	45	19471
1955	346	3223	Burnt River	10	-	10	
			Carbon	203	-	203	
			Control	20	-	20	
			Etzikom (Basal Blairmore)	1	-	1	
			Hilda	15	-	15	
			Hussar (Viking and Basal Colorado)	34	-	34	
			Rolling Hills (Basal Colorado)	6	-	6	
			Rosebud	35	-	35	
			Sundre	50	-	50	
			Westward Ho (Rundle Solution)	16	-	16	
			Windfall	323	-	323	
			Other small fields	95	-	95	20279
1956	384	3607	Beaver Creek	20	-	20	
			Beaverhill Lake (Blairmore)	3	-	3	
			Belloy (Notekwin)	7	-	7	
			Braeburn West	58	-	58	
			Chinook Ridge	45	-	45	
			Connorsville	18	-	18	
			Crossfield	150	-	150	
			Eagle Hill	30	-	30	
			Eaglesham (Gething and Cadomin)	8	-	8	
			Goodwin Lake	29	-	29	
			Innisfail	46	-	46	
			Kevisville	10	-	10	
			Leafland	10	-	10	

1	2	3	4	5	6	7	8
YEAR	WILDCAT WELLS PER YEAR	WILDCAT WELLS CUMULATIVE	NAME OF FIELD	DISPOSABLE GAS RESERVES AS OF DECEMBER 31, 1957 BCF	SALES TO DECEMBER 31, 1957 BCF	INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF	CUMULATIVE INITIAL DISPOSABLE GAS RESERVES AT DATE OF DISCOVERY BCF
1956 (CONT)			MAZEPPA	15	-	15	
			MOUNTAIN PARK	25	-	25	
			NORMANDVILLE (TRIASSIC, PERMO-PENN, RUNDLE)	15	-	15	
			OBED	10	-	10	
			PADDLE RIVER	17	-	17	
			WARBURG	12	-	12	
			WATERTON	700	-	700	
			WEST PRAIRIE	20	-	20	
			WILLESDEN GREEN	10	-	10	
			OTHER SMALL FIELDS	107	-	107	21644
1957	438	4045	BLUERIDGE	13	-	13	
			CALGARY (BASAL QUARTZ AND ELKTON)	58	-	58	
			CARSON CREEK	30	-	30	
			CHISHOLM	10	-	10	
			FAUST SOUTH	10	-	10	
			JOFFRE (D-2 SOLUTION)	11	-	11	
			KEYSTONE	65	-	65	
			LAMBERT CREEK	32	-	32	
			LOVETT	70	-	70	
			PINE CREEK	202	-	202	
			ROUND VALLEY	10	-	10	
			STOLBERG	45	-	45	
			OTHER SMALL FIELDS	127	-	127	22327

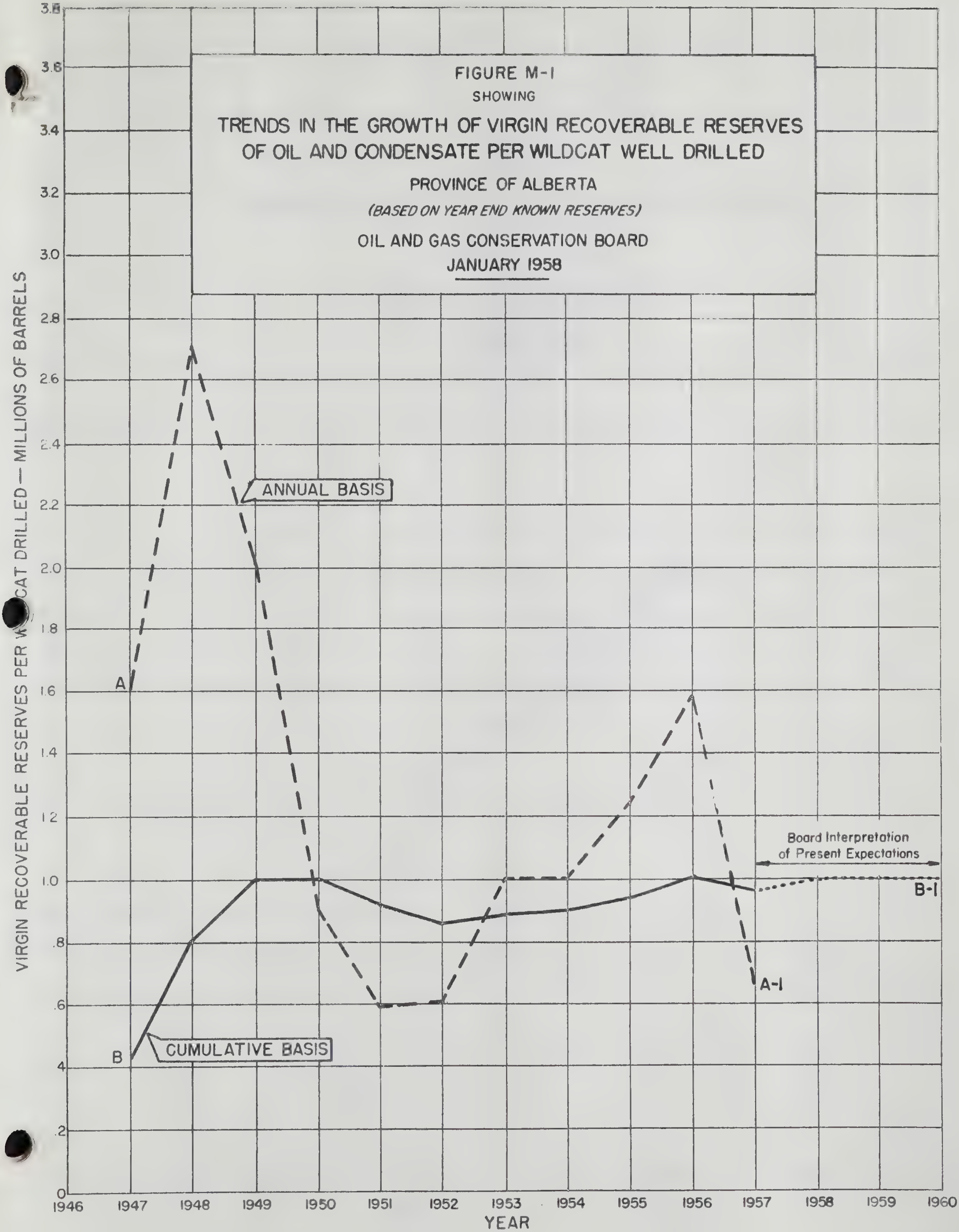
FIGURE M-I
SHOWING
TRENDS IN THE GROWTH OF VIRGIN RECOVERABLE RESERVES OF OIL AND CONDENSATE PER WILDCAT WELL DRILLED
PROVINCE OF ALBERTA
(BASED ON YEAR END KNOWN RESERVES)
OIL AND GAS CONSERVATION BOARD
JANUARY 1958
VIRGIN RECOVERABLE RESERVES PER WILDCAT DRILLED — MILLIONS OF BARRELS
YEAR
ANNUAL BASIS
CUMULATIVE BASIS
A
B
A-I
B-I
Board Interpretation of Present Expectations
0
.2
.4
.6
.8
1.0
1.2
1.4
1.6
1.8
2.0
2.2
2.4
2.6
2.8
3.0
3.2
3.4
3.6
3.8
1946
1947
1948
1949
1950
1951
1952
1953
1954
1955
1956
1957
1958
1959
1960

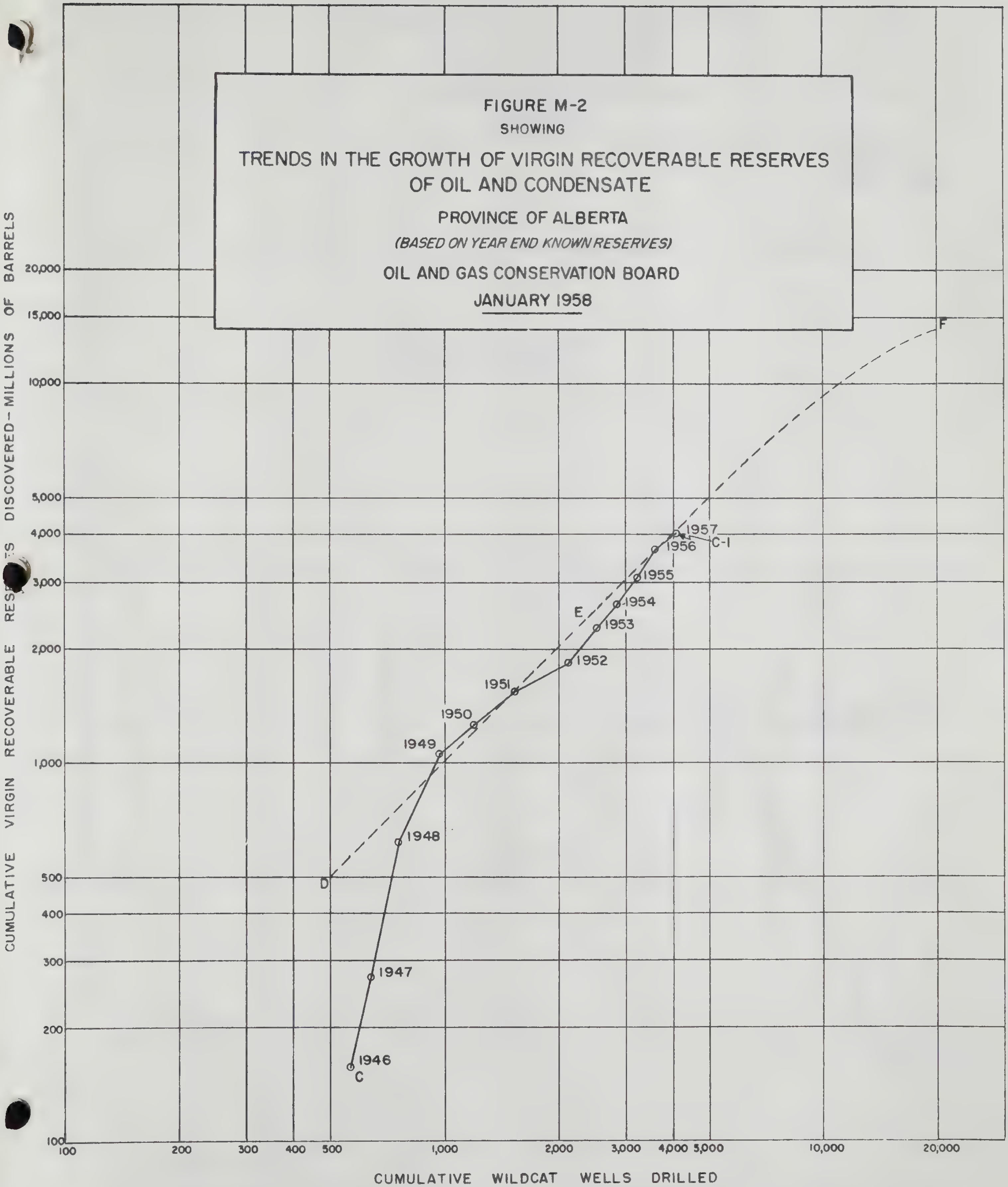
FIGURE M-2
SHOWING
TRENDS IN THE GROWTH OF VIRGIN RECOVERABLE RESERVES
OF OIL AND CONDENSATE
PROVINCE OF ALBERTA
(BASED ON YEAR END KNOWN RESERVES)
OIL AND GAS CONSERVATION BOARD
JANUARY 1958
CUMULATIVE VIRGIN RECOVERABLE RESERVES DISCOVERED - MILLIONS OF BARRELS
20,000
15,000
10,000
5,000
4,000
3,000
2,000
1,000
500
400
300
200
100
CUMULATIVE WILDCAT WELLS DRILLED
100
200
300
400
500
1,000
2,000
3,000
4,000
5,000
10,000
20,000
1946
C
1947
1948
D
1949
1950
1951
1952
E
1953
1954
1955
1956
1957
C-1
F

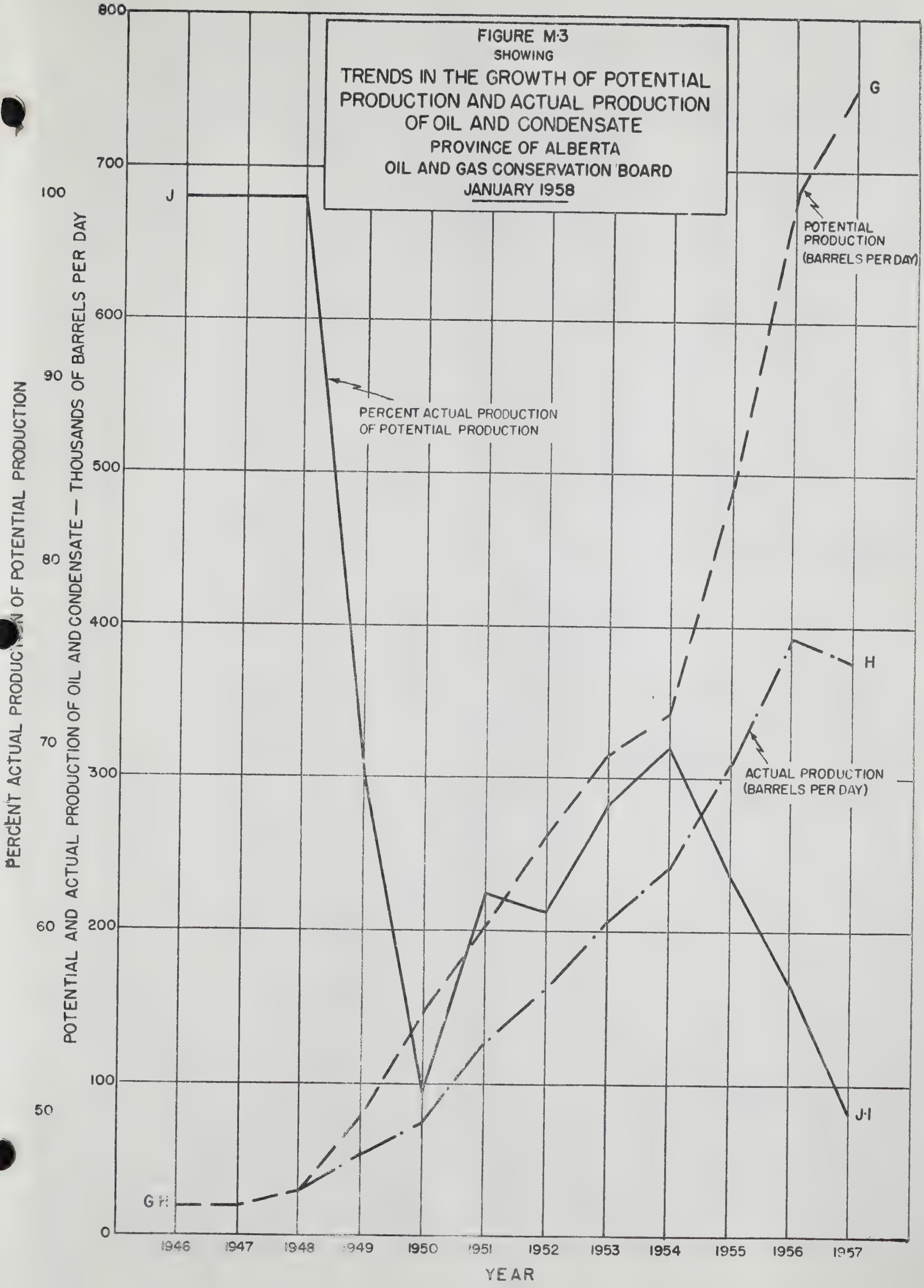
FIGURE M·3
SHOWING
TRENDS IN THE GROWTH OF POTENTIAL PRODUCTION AND ACTUAL PRODUCTION OF OIL AND CONDENSATE
PROVINCE OF ALBERTA
OIL AND GAS CONSERVATION BOARD
JANUARY 1958
PERCENT ACTUAL PRODUCTION OF POTENTIAL PRODUCTION
POTENTIAL AND ACTUAL PRODUCTION OF OIL AND CONDENSATE — THOUSANDS OF BARRELS PER DAY
PERCENT ACTUAL PRODUCTION OF POTENTIAL PRODUCTION
POTENTIAL PRODUCTION (BARRELS PER DAY)
ACTUAL PRODUCTION (BARRELS PER DAY)
J
G
H
J·1
G H
YEAR
1946
1947
1948
1949
1950
1951
1952
1953
1954
1955
1956
1957
0
100
200
300
400
500
600
700
800
50
60
70
80
90
100

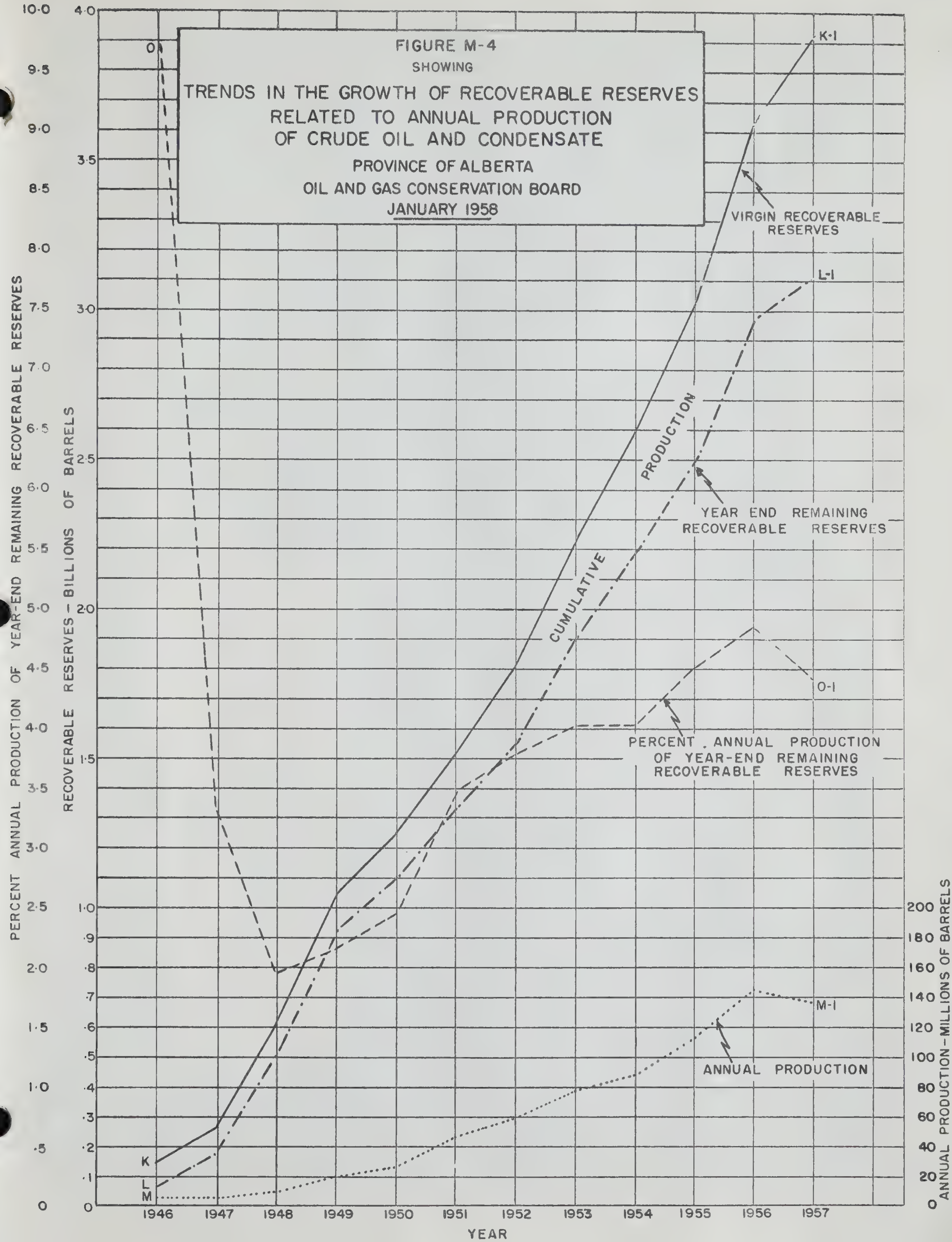

FIGURE M-4
SHOWING
TRENDS IN THE GROWTH OF RECOVERABLE RESERVES
RELATED TO ANNUAL PRODUCTION
OF CRUDE OIL AND CONDENSATE
PROVINCE OF ALBERTA
OIL AND GAS CONSERVATION BOARD
JANUARY 1958
PERCENT ANNUAL PRODUCTION OF YEAR-END REMAINING RECOVERABLE RESERVES
RECOVERABLE RESERVES - BILLIONS OF BARRELS
ANNUAL PRODUCTION-MILLIONS OF BARRELS
VIRGIN RECOVERABLE RESERVES
CUMULATIVE PRODUCTION
YEAR END REMAINING RECOVERABLE RESERVES
PERCENT ANNUAL PRODUCTION OF YEAR-END REMAINING RECOVERABLE RESERVES
ANNUAL PRODUCTION
K
L
M
O
K-1
L-1
O-1
M-1
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
.5
0
4.0
3.5
3.0
2.5
2.0
1.5
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
0
200
180
160
140
120
100
80
60
40
20
0
1946
1947
1948
1949
1950
1951
1952
1953
1954
1955
1956
1957
YEAR

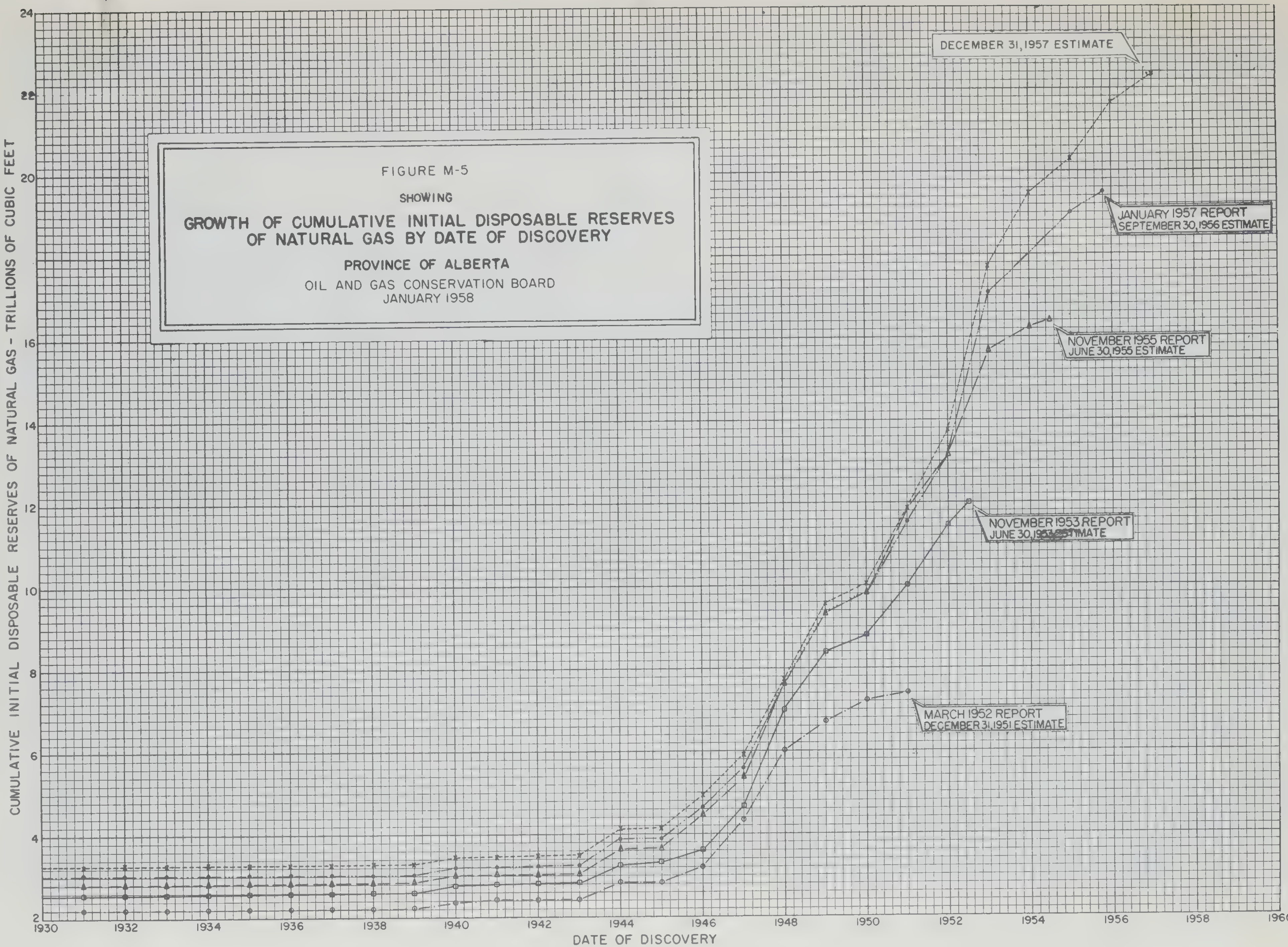
FIGURE M-5
SHOWING
GROWTH OF CUMULATIVE INITIAL DISPOSABLE RESERVES OF NATURAL GAS BY DATE OF DISCOVERY
PROVINCE OF ALBERTA
OIL AND GAS CONSERVATION BOARD
JANUARY 1958
DECEMBER 31, 1957 ESTIMATE
JANUARY 1957 REPORT
SEPTEMBER 30, 1956 ESTIMATE
NOVEMBER 1955 REPORT
JUNE 30, 1955 ESTIMATE
NOVEMBER 1953 REPORT
JUNE 30, 1953 ESTIMATE
MARCH 1952 REPORT
DECEMBER 31, 1951 ESTIMATE
CUMULATIVE INITIAL DISPOSABLE RESERVES OF NATURAL GAS - TRILLIONS OF CUBIC FEET
24
22
20
16
14
12
10
8
6
4
2
1930
1932
1934
1936
1938
1940
1942
1944
1946
1948
1950
1952
1954
1956
1958
1960
DATE OF DISCOVERY

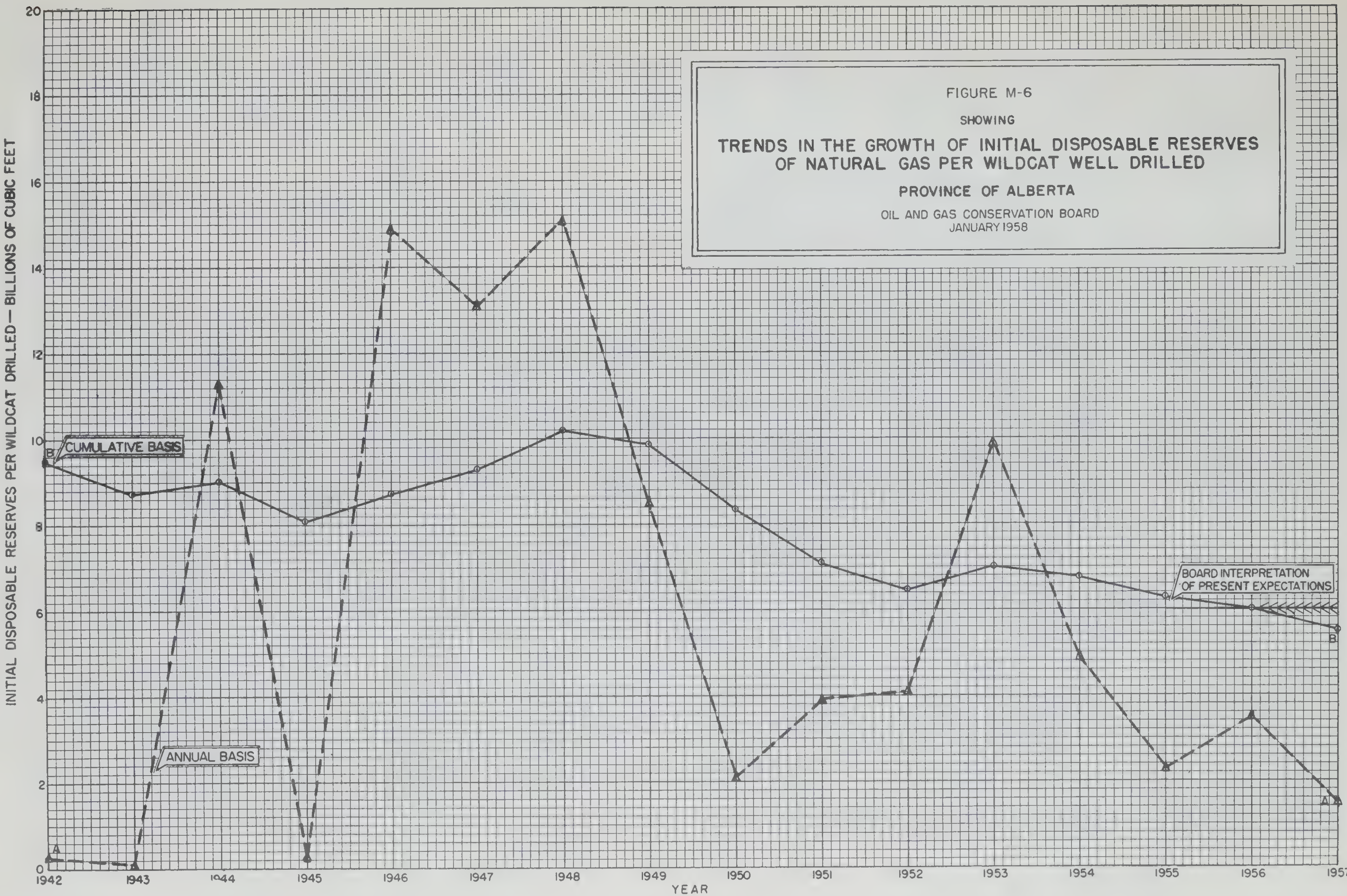
FIGURE M-6
SHOWING
TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES
OF NATURAL GAS PER WILDCAT WELL DRILLED
PROVINCE OF ALBERTA
OIL AND GAS CONSERVATION BOARD
JANUARY 1958
CUMULATIVE BASIS
ANNUAL BASIS
BOARD INTERPRETATION
OF PRESENT EXPECTATIONS
A
B
INITIAL DISPOSABLE RESERVES PER WILDCAT DRILLED — BILLIONS OF CUBIC FEET
YEAR
0
2
4
6
8
10
12
14
16
18
20
1942
1943
1944
1945
1946
1947
1948
1949
1950
1951
1952
1953
1954
1955
1956
1957

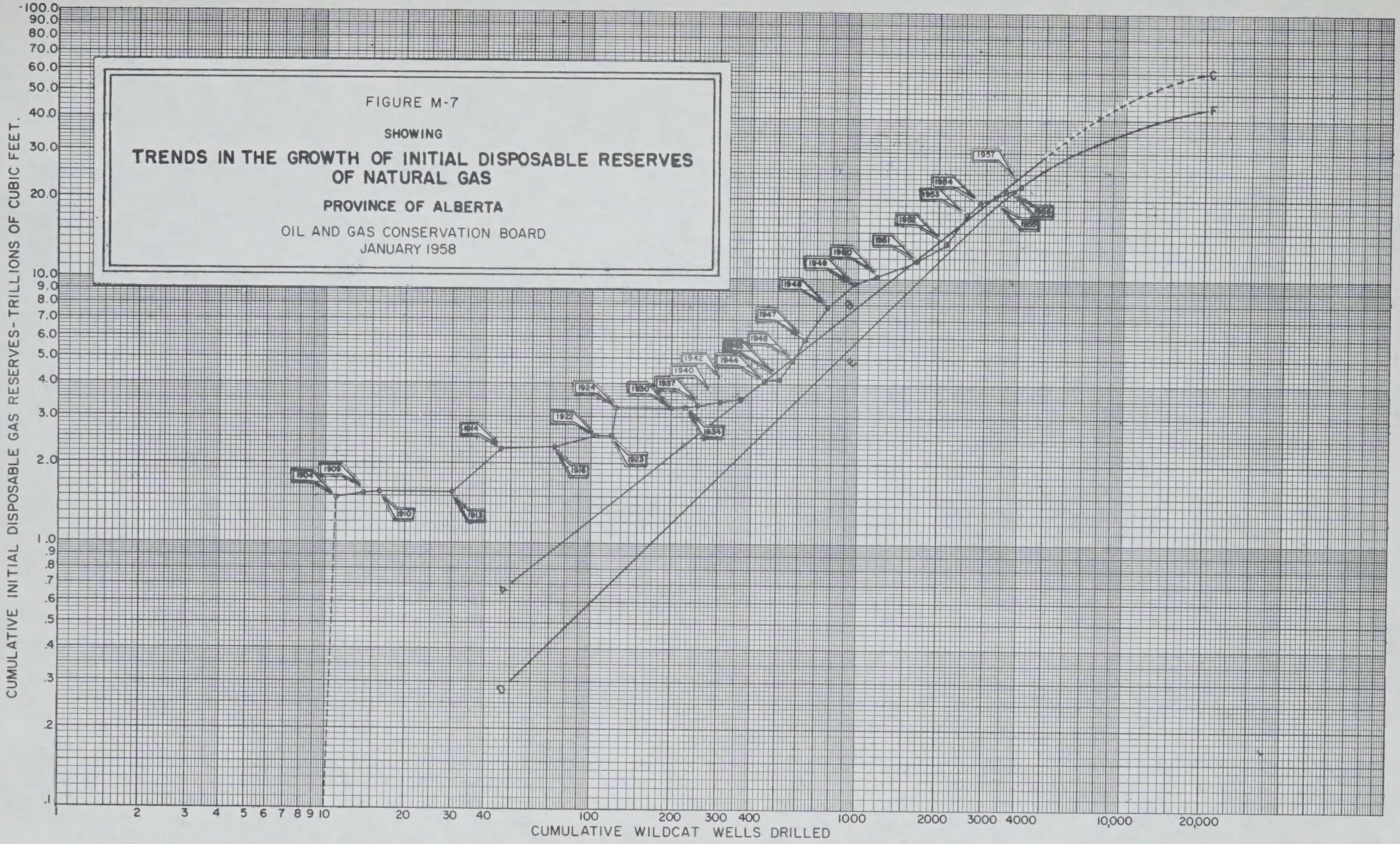

FIGURE M-7

SHOWING

TRENDS IN THE GROWTH OF INITIAL DISPOSABLE RESERVES OF NATURAL GAS

PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION BOARD
JANUARY 1958